

**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, 2019

☐ **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

(State or other jurisdiction of incorporation or organization)

N/A

(I.R.S. employer identification number)

116 Inverness Drive East, Suite 400

Englewood, Colorado

(Address of principal executive offices)

80112

(Zip code)

(303) 708-9740

(Registrant's telephone number, including area code)

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

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

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

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

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

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

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

Large accelerated filer ☐

Accelerated filer ☐

Non-accelerated filer ☒

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 \$28,438,541 as of June 28, 2019 (based on the last reported sales price of \$0.18 of such stock on the NASDAQ 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 March 31, 2020 was 198,303,021.

Documents incorporated by reference:

Portions of the registrant's definitive proxy statement relating to its 2020 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2019, are incorporated by reference to the extent set forth in Part III, Items 10-14 of this Form 10-K.

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PART I

Item 1. *Business.*

General

Ultra Petroleum Corp. and its wholly-owned subsidiaries (collectively the “Company”, “Ultra”, “our”, “we”, or “us”) is an independent exploration and production company focused on developing and producing its long-life natural gas reserves in the Pinedale and Jonah fields of the Green River Basin of southwest Wyoming. The Company was incorporated in 1979, under the laws of the Province of British Columbia, Canada. Ultra remains a Canadian company, and since March 2000, has operated under the laws of Yukon, Canada pursuant to Section 190 of the *Yukon Business Corporations Act*.

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, as amended (the “Exchange Act”), are available free of charge to the public on the Company’s website at www.ultrapetroleum.com as soon as reasonably practicable after such material is electronically filed with, or furnished to, the SEC. You may also request a copy of these filings at no cost by making written or telephone requests for copies to Ultra Petroleum Corp., Investor Relations, 116 Inverness Drive East, Suite 400, Englewood, CO 80112, (303) 708-9740, ext. 9898. The Securities and Exchange Commission (“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.

Oil and Gas Properties Overview

Principal Operating Area

The Company conducts operations exclusively in the United States. Its operations in southwest Wyoming have historically focused on producing and 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, 2019, Ultra owned interests in approximately 117,000 gross (83,000 net) acres in Wyoming covering approximately 190 square miles. Following the sale of the Company’s Pennsylvania properties in late 2017 and Utah assets in late 2018, all oil and gas operations are now focused in the Pinedale and Jonah fields.

Mission and Strategy

Ultra’s mission and strategy is focused on disciplined capital allocation decisions, generating operating cash flows, reducing its indebtedness, and preserving future potential drilling inventory for more constructive natural gas prices. The Company’s emphasis on these elements is critically relevant as the natural gas commodity price has eroded further over the course of 2019, and the forward strip pricing remains at depressed levels. Given Ultra’s focus on profitability and generating operating cash flows to repay its indebtedness, the Company elected to suspend drilling operations in the third quarter of 2019, as the investment returns were unattractive in the current commodity price environment. The Company determined it is in the best interest of its stakeholders to retain core personnel necessary in order to operate its prolific asset base safely, efficiently, and profitably; to ensure necessary regulatory and environmental compliance; to continue to fulfill its obligations as a public reporting company; to continue to dedicate appropriate resources to studying the underlying geologic and subsurface in order to maximize the value of the Pinedale and Jonah fields; and to prepare to resume a drilling program with much of the historical knowledge and intellectual property developed over many years by Ultra personnel.

Due to the suspension of the drilling program, the Company has no estimated proved undeveloped (“PUD”) reserves as of December 31, 2019, with respect to its properties because it has elected not to drill new wells in the current commodity price environment. Additionally, as noted below, the Company has a \$5 million limitation of capital expenditures per quarter as set forth in the Fifth Amendment to the Credit Agreement (as defined below). The Company previously reported estimated PUD reserves in annual SEC filings, and, if in the future we can satisfy the reasonable certainty criteria as prescribed under the SEC requirements, we could include PUD reserves in future filings.

Liability Management Activities. In 2019, Ultra continued its liability management activities. In the first quarter of 2019, the Company executed incremental note exchange transactions of \$44.6 million of the 6.875% Senior Notes due 2022 (the “2022 Notes”) of Ultra Resources, Inc., a Delaware corporation (“Ultra Resources”), a wholly owned subsidiary of the Company, for \$27.0 million of new 9.00% Cash / 2.00% PIK Senior Secured Second Lien Notes due July 2024 (the “Second Lien Notes”) (such transaction, the “Incremental Exchange”).

The Company also attempted to exchange a portion of the outstanding 7.125% Senior Notes due 2025 (the “2025 Notes”) of Ultra Resource, for new 9.00% Cash / 2.50% PIK Senior Secured Third Lien Notes due 2024 of Ultra Resources, as allowed by the current Credit Agreement, Term Loan Agreement (as defined below) and Second Lien Indenture (as defined below). The Company ultimately terminated this exchange offer in July 2019, as it determined the economic terms and the additional layer of secured indebtedness were not in the best interest of the Company.

In February and March 2020, the Company entered into confidentiality agreements and commenced discussions with certain holders of the Company’s long-term debt and their legal and financial advisors. The Company previously engaged with certain debtholders regarding

potential out-of-court restructuring, but as previously disclosed on March 5, 2020, such negotiations are no longer occurring. Negotiations and discussions with certain other debtholders and their advisors are now ongoing regarding a potential in-court restructuring, although as of the date of this filing no definitive agreements have been reached regarding any amendments, restructurings or other transactions relating to the Company's indebtedness.

If an agreement is reached and the Company pursues a restructuring, it may be necessary for the Company to file a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code or the Canadian Bankruptcy and Insolvency Act in order to implement an agreement through the confirmation and consummation of a plan of reorganization approved by the bankruptcy court in the bankruptcy proceedings. The Company also may conclude that it is necessary to initiate proceedings under Chapter 11 of the United States Bankruptcy Code to implement a restructuring of its obligations even if it is unable to reach an agreement with its creditors and other relevant parties regarding the terms of such a restructuring. In either case, such a proceeding could be commenced in the near term.

As discussed under Item 7 — Management's Discussion and Analysis of Financial Condition and Results of Operations, the Company believes it will require a significant restructuring of its balance sheet in order to continue as a going concern in the long term as a result of extremely challenging current market conditions. The Company has based this belief on assumptions and estimates which are to some degree subjective and may vary considerably from actual results, and it could spend its available financial resources less or more rapidly than currently expected.

Strategic Alternatives. As announced in November 2019, the Company previously engaged Tudor, Pickering, Holt & Co. as an advisor to assist management and the Board of Directors in evaluating a range of strategic alternatives, including without limitation, a corporate sale, merger or other business combination, one or more strategic acquisitions or divestitures, or other transactions. The Company terminated this engagement in the first quarter of 2020, but may elect to reengage this advisor at a later date.

The Company continues to explore a number of other potential actions in order to address its liquidity and balance sheet issues, including, among other things, amendments and waivers.

There is no assurance that these initiatives will result in a transaction that is accretive to the per share value of the Company. The Company has not set a timetable for the evaluation process and is continuing to evaluate the opportunities to resume a capital program on a more diversified regional basis or to be a consolidator with other operators, subject to increasing commodity prices.

Commodity Price Volatility. Beginning in March 2020, oil and natural gas commodity prices have experienced extreme volatility primarily attributable to decreased demand resulting from COVID and the actions of OPEC and other oil exporting nations. These events have limited our ability to execute on our business plan and adversely affected our business. Please see "*Risk Factors-- Outbreaks of communicable diseases could adversely affect our business, financial condition and results of operations*" and "*--The ability or willingness of OPEC and other oil exporting nations to set and maintain production levels has a significant impact on oil and natural gas commodity prices.*"

Oil and Gas Development 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 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.

Focus on Maximizing Value. Ultra strives to maintain one of the lowest cost structures in the industry in terms of both producing and adding oil and natural gas reserves. In 2019, the Company continued 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 and regulatory best practices, maintaining strict safety and environmental standards, and recruiting and retaining top talent within the Company. This is evidenced by the Company's low-cost operations, the improvement in well costs, and the advancement of lower-cost drilling processes that served to enhance investment returns in 2019.

Credit Agreement Activity

Ultra Resources entered into a Credit Agreement (as amended, the "Credit Agreement") as the borrower with the Company and UP Energy Corporation, as parent guarantors, with Bank of Montreal, as administrative agent (the "RBL Administrative Agent"), and with the other lenders party thereto from time to time (collectively, the "RBL Lenders"), providing for a revolving credit facility (the "Revolving Credit Facility") subject to a borrowing base redetermination, which limits the aggregate amount of first lien debt under the Revolving Credit Facility and Term Loan Agreement (as defined below).

During 2019, the Company met all of its financial obligations, including debt service and interest obligations, and was in compliance with the requirements of its various debt instruments. The Company proactively negotiated amendments to its Credit Agreement twice during 2019 which aligned with the stated goals of directing cash flows to reduce indebtedness. At December 31, 2019, the Company had a commitment of \$200.0 million under its Revolving Credit Facility and a borrowing base of \$1.175 billion, of which \$64.7 million was outstanding. Additionally, the Company had \$6.7 million of letters of credit outstanding. Availability under the Revolving Credit Facility is defined as the undrawn portion of the commitment, plus the unrestricted cash of the Company, and net of any outstanding letters of credit.

On February 14, 2020, Ultra Resources entered into the Sixth Amendment to the Credit Agreement (the “Sixth Amendment”) with the RBL Administrative Agent and the RBL Lenders party thereto. Pursuant to the Sixth Amendment and the spring 2020 redetermination, the Borrowing Base (as defined in the Credit Agreement) was reduced to \$1.075 billion, with \$100 million attributed to the Revolving Credit Facility, effective on April 1, 2020. The Sixth Amendment also reduced the excess cash threshold to \$15 million as part of the anti-cash hoarding provisions and established quarterly, rather than semi-annual, redeterminations of the borrowing base. The next borrowing base redetermination is scheduled to be completed on or before July 1, 2020.

Given the potential for decreases in future commodity prices, the borrowing base level is subject to redetermination risk. If the borrowing base or the commitment amount were redetermined below the levels of outstanding indebtedness associated with the Revolving Credit Facility and Term Loan Agreement, or if the commitment amount was inadequate to fund ongoing operations, the Company could potentially trigger mandatory repayment provisions of the Revolving Credit Facility or demands to reduce the Term Loan Agreement balance. Given the overall credit metrics of the Company and the state of the debt markets, such a situation could result in the Company having an event of default under its debt obligations.

The report of the Company’s independent registered public accounting firm that accompanies its audited consolidated financial statements in this Annual Report on Form 10-K contains an explanatory paragraph regarding the substantial doubt about the Company’s ability to continue as a going concern. As a result, the Company has reclassified all of its total outstanding debt as current. Because the audit report prepared by the Company’s independent registered public accounting firm includes an explanatory paragraph expressing uncertainty as to its ability to continue as a going concern, the Company is in default under each of the Credit Agreement and Term Loan Agreement on April 14, 2020 when the Company delivers its financial statements to the lenders under the Credit Agreement. There is a 30-day grace period related to this covenant in the Credit Agreement. If the Company does not obtain a waiver or other suitable relief from the lenders under the Credit Agreement or the Term Loan Agreement before the expiration of the 30-day grace period, an event of default under each of the Credit Agreement and Term Loan Agreement would occur. As a result of the going concern qualification in the independent registered public accounting firm’s report to the December 31, 2019 financial statements, the Company’s immediate liquidity is limited to cash as it will not have access to its Revolving Credit Facility beginning on April 15, 2020.

See Part II, Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources” for a description of the Revolving Credit Facility and other debt instruments.

2018 and 2017 Divestitures

The Company previously had operations in the Uinta Basin in Utah and in north central Pennsylvania.

During the third quarter of 2018, the Company completed the sale of its Utah assets for net cash proceeds of \$69.3 million, including transaction fees of \$0.6 million. The divested assets consisted primarily of oil and gas properties. Prior to the sale, production from the Company’s Utah assets totaled approximately 420,000 Bbl of oil and 745,000 Mcf of natural gas in 2018.

During the fourth quarter of 2017, the Company divested its properties in the Pennsylvania Devonian aged Marcellus Shale, for net cash proceeds of approximately \$115.0 million. Prior to the sale, production from the Pennsylvania assets totaled approximately 11.2 million Mcf of natural gas in 2017.

Exploration and Production

See Item 2. “Properties” for a description of our properties.

Green River Basin, Wyoming

During 2019, the Company completed and turned to sales 93 gross (77.6 net) vertical and 1 gross (0.9 net) horizontal wells operated by the Company and others in Wyoming and continued to improve its drilling and completion efficiency on its operated wells. Of these wells, the Company operated 71 gross (70.3 net) vertical wells and 1 gross (0.9 net) horizontal wells. In line with the Company’s commitment to make its operations more efficient, the Company’s development was focused on vertical wells in 2019. The operated well costs for vertical wells declined since 2017 to \$2.87 million per well during third quarter 2019 at which time the Company suspended its drilling operations. The decline of well costs in 2019 is a result of an increased success rate of the two-string drilling design over the year, as well as overall improvements in efficiencies and cost management throughout the year. Included in the well results was the successful completion of seven wells with the two-string design in third quarter 2019 at an average well cost of \$2.65 million per well, highlighting improvement of the selection of the locations for this application in the Pinedale Field, as well as the knowledge gained over the course of the year as to the application of the techniques deployed. The Company operates 92% of its production in the Pinedale field.

During 2020, the Company plans to continue its focus on cash flow generation and reduction of indebtedness. Development activity may occur if there is a sustained increase in the expected realized natural gas price and the Company amends its Credit Agreement to remove the limitation of capital investments to amounts below \$5.0 million per quarter, which was implemented in connection with the Fifth Amendment to the Credit Agreement on September 16, 2019 (the “Fifth Amendment”).

Marketing and Pricing

Overview

During the year ended December 31, 2019, 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 and ownership interests in wells operated by another operator in the same area.

During 2019, 96% of the Company's production and 86% of its revenues were attributable to natural gas, with the balance attributable to associated condensate and crude oil.

The Company's natural gas and oil revenues are determined by prevailing market prices in the Rocky Mountain region of the United States, specifically, southwest Wyoming, as virtually all of its natural gas is sold at the Inside FERC First of Month Index for Northwest Pipeline — Rocky Mountains ("NwRox"). The NwRox and New York Mercantile Exchange ("NYMEX") is the price that is reflective of the Company's gas sold in the Opal, Wyoming area.

The NwRox price can be volatile, particularly in peak winter and summer periods, as evidenced in December 2019 when natural gas at that delivery point was selling for \$0.97 per MMBtu above NYMEX pricing for natural gas. During 2019, the negative differential of NwRox to Henry Hub averaged \$0.04 per MMBtu, with a range of negative \$0.74 per MMBtu to a positive differential of \$0.97 per MMBtu for first of month Inside FERC basis at Opal.

Natural Gas Marketing

Ultra currently sells all 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".

Midstream services. For its natural gas production in Wyoming, the Company has entered into various gathering and processing agreements with 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 maintain and upgrade the facilities in southwest Wyoming to ensure reliability and certainty of operations. The Company believes that the capacity of the midstream infrastructure related to its production will continue to be adequate to allow it to sell all 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 in the western United States, 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.

Following the completion of the Rockies Express and Ruby pipelines, 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, as compared to prior years when constraints were prevalent in the region. However, from 2017 to 2018, NwRox basis 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 2019, NwRox basis improved to average 98.6% of Henry Hub due increased demand and reduced supply in Western US markets. What has become more pronounced over the last several years is a widening and favorable distinction between natural gas priced based on NwRox compared to Colorado Interstate Gas ("CIG"). Over the course of 2019, NwRox outperformed CIG by approximately \$0.45 per MMBtu with CIG pricing at 81.6% of Henry Hub.

While trades indicate that the basis differentials for the forward-looking basis market for 2020 and 2021 are negative to Henry Hub by approximately \$0.23 per MMBtu and \$0.36 per MMBtu, respectively, the winter seasons of 2018/2019 and 2019/2020 demonstrate the potential for NwRox basis to trade at a significant premium to Henry Hub during the winter seasons. The actual results for January and February 2020 were positive by \$1.00 per MMBtu and \$0.07 per MMBtu, respectively.

The table below provides a historical perspective on average quarterly basis differentials for Wyoming natural gas (NwRox). The basis differential is expressed as a percentage of the Henry Hub price as reported by Inside FERC Report from S&P and Platt's M2M (Mark to Market) Report on December 31, 2019 and 2018, respectively.

	2019			
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
NwRox	120%	79%	86%	104%
NYMEX (per MMBtu)	\$ 3.15	\$ 2.64	\$ 2.23	\$ 2.50

	2018			
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
NwRox	83%	70%	80%	103%
NYMEX (per MMBtu)	\$ 3.00	\$ 2.80	\$ 2.90	\$ 3.64

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, adjusted for a negotiated location/transportation differential. All of the Company's condensate sales are denominated in U.S. dollars per barrel and are paid monthly. 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. Over 93% of oil is transported via pipeline, thereby greatly reducing the cost of transportation. During 2019, the Company realized a positive differential of \$2.83 per Bbl, to a West Texas Intermediate price. The improvement in the differential was a result of strong refining demand for the quality of condensate produced in the Pinedale area. This trend of strengthening oil differentials is expected to continue in 2020, as evidenced by the contracts in place through 2020 at a positive differential of \$3.74 per Bbl. With the drastic drop in demand for Refined Products due to the response to COVID-19, Salt Lake area refineries may reduce their demand for Crude Oil. There is a risk that regional storage for Crude Oil may be insufficient for area producers including Ultra to continue full production rates in the second quarter of 2020. Please see "*Risk Factors--Outbreaks of communicable diseases could adversely affect our business, financial condition and results of operations*" and "*--The ability or willingness of OPEC and other oil exporting nations to set and maintain production levels has a significant impact on oil and natural gas commodity prices.*"

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, collars and puts with creditworthy financial counterparties (See Note 8 for additional information), or through the use of fixed price, forward sales of physical product. Under the Company's Credit Agreement, the Company is subject to minimum hedging requirements through March 31, 2020, after which there is no minimum hedging requirement from the lenders. During the quarterly period beginning on September 30, 2019 and ending on March 31, 2020, the Company was required to hedge a minimum of 50% of projected proved developed producing natural gas reserve volumes projected to be produced in the specified quarter.

The Company considers the requirements of the Credit Agreement when developing its hedging policy. The Company's management and board of directors has a Hedge Committee that reviews the forecast production, the requirements under the Credit Agreement, and the market outlook to determine the timing and the manner in which to hedge with the underlying goal to provide a predictable level of cash flow while preserving some flexibility to participate in upward price movements.

Major customers

A major customer is defined as one that individually accounts for 10% or more of the Company's total revenues during the year. In 2019, sales to Nevada Power Company and Pacific Gas and Electric accounted for 11.1% and 10.2% of our total revenue, respectively. In 2018 and 2017, the Company had no single customer 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 15. The Company takes measures to ensure collectability with its purchasers through regular credit monitoring and reviews. As necessary, the Company requires prepayment, letters of credit or parental guarantees from its purchasers for the periods of exposure. The Company did not have any outstanding, uncollectible accounts for its natural gas and oil sales at December 31, 2019.

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, 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 WOGCC has authorized drilling density up to one well per five acres in the Pinedale field and up to one well per ten 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. See Item 1A. "Risk Factors" for additional information regarding environmental regulations.

In December 2018 and January 2019, a portion of the federal government shut down after Congress failed to pass a continuing resolution. This shut-down included all nonessential personnel at the BLM, including BLM staff tasked with processing drilling permits and sundries. The Company has adequate inventory of approved applications for permit to drill if and when the Company's elects to resume its drilling program,

but any changes or deviations from what is approved in these permits cannot be approved during a shut-down, should another one occur, thus creating an execution risk. In addition, such government disruptions could delay or halt the granting and renewal of the permits, approvals, and certificates required to conduct our operations.

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’s subsidiaries that own mineral leases qualify 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 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 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 U.S. Environmental Protection Agency (“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 December 2016, the EPA and several environmental groups entered into a consent decree under which the EPA committed to propose 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. In April 2019, the EPA made the determination that revisions to the regulations were not necessary at that time, concluding that

any adverse effects related to oil and gas waste were more appropriately and readily addressed within the framework of existing state regulatory programs. 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, in Wyoming any waste material exceeding specified thresholds is subject to controls and guidance by the Wyoming Department of Environmental Quality Solid and Hazardous Waste Division, which determines how and where NORM wastes will be disposed of.

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 SDWA'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.

Some states, including Wyoming, 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. 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. In December 2017, BLM rescinded regulations that it previously enacted for hydraulic fracturing activities on federal lands; that rescission has been challenged by several environmental groups and states in ongoing litigation. Further, the EPA has announced an initiative under the Toxic Substances Control Act to develop regulations governing the disclosure and evaluation of hydraulic fracturing chemicals and is working on regulations for wastewater generated by hydraulic fracturing.

Finally, in some instances, the operation of underground injection wells for the disposal of waste has been alleged to cause earthquakes. In Oklahoma, for example, such issues have led to orders prohibiting continued injection or the suspension of drilling in certain wells identified as possible sources of seismic activity. Such concerns also have resulted in stricter regulatory requirements in some jurisdictions relating to the location and operation of underground injection wells. Although our operations are not located in those jurisdictions, any future orders or regulations addressing concerns about seismic activity from well injection in jurisdictions where we operate could affect our operations.

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. These classes of persons, or so-called potentially responsible parties ("PRPs"), 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. NEPA 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 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 NEPA, including the requirement that an EA or EIS be prepared. The requirements of the NEPA 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. Moreover, in January 2020, the White House Council on Environmental Quality (“CEQ”) proposed changes to NEPA regulations designed to overhaul the system and speed up federal agencies’ approval of projects. Among other things, the rule proposes to narrow the definition of “effects” to exclude the terms “direct,” “indirect,” and “cumulative” and redefine the term to be “reasonably foreseeable” and having “a reasonably close causal relationship to the proposed action or alternatives.” Changes to the NEPA regulations could impact our operations and our ability to obtain governmental permits. We continuously evaluate the effect of new rules on our business

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”) and analogous state laws regulate air emissions from stationary and mobile sources and establishes National Ambient Air Quality Standards for six criteria pollutants. The CAA is a federal law, but states, tribes and local governments do much of the work to develop EPA-approved plans to achieve these standards and meet the CAA’s requirements. 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 and National Emission Standards for Hazardous Air Pollutants programs under the CAA impose specific requirements affecting the oil and gas industry 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 June 2016, the EPA finalized rules to reduce methane and volatile organic compound (“VOC”) emissions from new, modified or reconstructed sources in the oil and natural gas sector; however, in September 2018, under a new administration, the EPA proposed to remove transmission and storage activities from the purview of the rules, thereby rescinding the VOC and methane emissions limits applicable to those activities. The proposed rule would also rescind the methane limit emissions for production and processing sources but would maintain emissions limits for VOCs. In the alternative, the EPA also proposed to simply rescind the methane requirements for all oil and natural gas sources, without removing any activities from the source category. Similarly, in September 2018, the BLM issued a rule that relaxes or rescinds certain requirements of regulations it had previously enacted to reduce methane emissions from venting, flaring, and leaks during oil and gas operations on public lands; California and New Mexico have challenged that rule in ongoing litigation. In addition, in April 2018, a coalition of states filed a lawsuit in federal district court aiming to force the EPA to establish guidelines for limiting methane emissions from existing sources in the oil and natural gas sector; that lawsuit is pending (as of October 2019, the EPA had requested a stay of the litigation pending the outcome of its proposed overhaul of the 2016 methane requirements). Several states are pursuing similar measures to regulate emissions of methane from new and existing sources within the oil and natural gas source category. 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 and cause major delays in construction, effectively depressing new development. 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 could be significant.

Clean Water Act. The CWA and analogous state laws restrict the discharge of pollutants, including produced waters and other oil and natural gas wastes, into state waters and waters of the United States, a term broadly defined to include, among other things, certain wetlands. Under the CWA, 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, oil, and hazardous substances and also 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 June 2015, the EPA and the Army Corps of Engineers (“Corps”) issued new rules defining the scope of the EPA’s and the Corps’ jurisdiction over wetlands (the “Clean Water Rule”). The Clean Water Rule was stayed nationwide by the U.S. Sixth Circuit Court of Appeals, but on January 22, 2018, the U.S. Supreme Court ruled that jurisdiction to hear challenges to the rule lies with the federal district courts, and the Sixth Circuit’s stay was dissolved in February 2018. On July 27, 2017, the EPA published a proposed rule to rescind the Clean Water Rule and re-codify the regulatory text that existed prior to 2015 defining the “waters of the United States.” In December 2018, the EPA and the Corps issued a proposed rule revising the WOTUS definition that would provide discrete categories of jurisdictional waters and tests for determining whether a particular water body meets any of those classifications. In October 2019, the EPA issued a final rule repealing the Clean Water Rule (which became effective in December 2019 and already has been challenged in federal district courts in New Mexico, New York, and South Carolina). In January 2020, the EPA announced a final rule redefining “waters of the United States.” Several groups have already announced their intentions to challenge the final revision rule. To the extent the repeal and revision rules are successfully challenged, and the Clean Water Rule is enforced in jurisdictions in which we operate or a replacement rule expands the scope of the CWA jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas.

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. This 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 (“MBTA”), 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. 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, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to make listing decisions and critical habitat designations where necessary for over 250 species. The U.S. Fish and Wildlife Service issued a 7-Year National Listing Workplan in September 2016. However, on July 25, 2018, the U.S. Fish and Wildlife Service proposed three revisions to regulations regarding critical habitat designation, interagency cooperation, and protection of threatened species that it believes are necessary to address industry and landowner concerns. The U.S. Department of the Interior also issued an opinion on December 22, 2017 that would narrow certain protections afforded to migratory birds pursuant to the MBTA. In response to this opinion, two separate lawsuits were filed on May 24, 2018 in the U.S. District Court for the Southern District of New York challenging the Department of the Interior’s interpretation of the MBTA. On September 5, 2018, eight states also filed suit in the U.S. District Court for the Southern District of New York challenging the opinion. All such litigation is ongoing. The identification or designation of previously unprotected species as threatened or endangered in areas where our operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our development activities that could have an adverse impact on our ability to develop and produce reserves. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our 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 required 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. The Company 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.

In addition, Congress has from time to time considered adopting legislation to reduce emissions of GHGs, and a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs. Cap and trade programs typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. On an international level, the United States was one of 175 countries to sign an international climate change agreement in Paris, France that requires member countries to set their own GHG emission reduction goals beginning in 2020. However, on June 1, 2017, President Trump announced that the United States will withdraw from the Paris Agreement, and on November 4, 2019, the U.S. submitted formal notification of its withdrawal to the United Nations. The withdrawal will take effect one year from delivery of the notification, although there is a possibility that a new administration could choose to rejoin the Paris Agreement. Various states and local governments have vowed to continue to enact regulations to achieve the goals of the Paris Agreement.

Any legislation or regulatory programs to reduce GHG emissions could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. Moreover, incentives to conserve energy or use alternative energy sources as a means of addressing climate change could reduce demand for the oil and natural gas we produce. In addition, parties concerned about the potential effects of climate change have directed their attention at sources of funding for energy companies, which has resulted in certain financial institutions, funds and other sources of capital, restricting or eliminating their investment in oil and natural gas activities. Finally, it should be noted that many 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. For example, under a new OSHA standard limiting respirable silica exposure, the oil and gas industry must implement engineering controls and work practices to limit exposures below the new limits by June 23, 2021. Failure to comply with OSHA requirements can lead to the imposition of penalties. For example, 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, 2019, the Company had 151 full-time employees, including officers. The Company believes that its relationship with its employees is satisfactory. None of our employees are represented by a labor union or subject to a collective bargaining agreement.

Seasonality and Cyclicalities

Seasonal weather conditions and lease stipulations can limit the drilling and producing activities and other operations in the areas in which the Company operates. These seasonal conditions can pose challenges for meeting the well drilling objectives and increase competition for equipment, supplies and personnel, which could lead to shortages and increase costs or delay operations. For example, the Company's operations may be impacted by ice and snow in the winter and by electrical storms and high temperatures in the spring and summer, as well as by wild fires in the fall.

The demand for natural gas typically decreases during the summer months and increases during the winter months. Seasonal anomalies sometimes lessen or amplify this fluctuation. In addition, certain natural gas consumers utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can also lessen seasonal demand fluctuations. As a corollary, the demand for our products can be impacted by weather in the western United States from temperature fluctuations outside of normal ranges, moisture levels in the Pacific Northwest to the extent it impacts hydroelectric power generation, and more broadly across the United States when there are unusual cold events or lack of winter weather.

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.

Principal Executive Offices

The Company is incorporated under the laws of Yukon, Canada, with headquarters in Englewood, Colorado. The principal executive offices are located at 116 Inverness Drive East, Suite 400, Englewood, Colorado, 80112. The main telephone number is (303) 708-9740.

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 have concluded that we need to restructure our balance sheet to continue as a going concern over the long term, and we can provide no assurances of the terms of any such restructuring transaction in which we may engage or how any such transaction will impact

our security holders. We may need to seek relief under Chapter 11 of the United States Bankruptcy Code or the Canadian Bankruptcy and Insolvency Act, which could result in little or no consideration to our debt and equity holders.

As a result of our significant indebtedness and extremely challenging current market conditions, we believe we will require a significant restructuring of our balance sheet in order to continue as a going concern in the long term. We have based this belief on assumptions and estimates which are to some degree subjective and may vary considerably from actual results, and we could spend our available financial resources less or more rapidly than currently expected.

In February and March 2020, we entered into confidentiality agreements and commenced discussions with certain holders of the Company's long-term debt and their legal and financial advisors. Negotiations and discussions with certain debtholders and their advisors are ongoing, although as of the date of this filing no definitive agreements have been reached regarding any amendments, restructurings or other transactions relating to the Company's indebtedness.

There can be no assurance that our efforts will result in any agreement or what the terms of any agreement will be. If an agreement is reached and we pursue a restructuring, it may be necessary for us to file a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code or the Canadian Bankruptcy and Insolvency Act in order to implement an agreement through the confirmation and consummation of a plan of reorganization approved by the bankruptcy court in the bankruptcy proceedings. We also may conclude that it is necessary to initiate proceedings under Chapter 11 of the United States Bankruptcy Code to implement a restructuring of our obligations even if we are unable to reach an agreement with our creditors and other relevant parties regarding the terms of such a restructuring. In either case, such a proceeding could be commenced in the near term. If a plan of reorganization is implemented in a bankruptcy proceeding, it is possible that holders of claims and interests with respect to, or rights to acquire, our equity securities would be entitled to little or no recovery, and those claims and interests may be canceled for little or no consideration. If that were to occur, we anticipate that all or substantially all of the value of all investments in our equity securities would be lost and that our equity holders would lose all or substantially all of their investment. It is also possible that our other stakeholders, including holders of our Second Lien and Unsecured Notes, will receive little or no consideration for their claims.

The audit report we received with respect to our fiscal year 2019 consolidated financial statements contains an explanatory paragraph expressing uncertainty as to our ability to continue as a going concern. Our Credit Agreement and Term Loan Agreement require us to deliver audited, consolidated financial statements without a going concern or like qualification or exception. As a result, unless we obtain a waiver of this requirement, subject to a 30-day grace period, we will be in default under our Credit Agreement and Term Loan Agreement after we deliver our financial statements to the lenders thereunder. Our failure to obtain a waiver of this requirement under the Credit Agreement and Term Loan Agreement within the applicable grace period could result in an acceleration of all of our outstanding debt obligations thereunder.

The sustained periods of low natural gas prices combined with the recent precipitous drop in crude oil prices and our substantial indebtedness led us to determine that there is substantial doubt about our ability to continue as a going concern. Additionally, there is substantial doubt regarding our ability to maintain adequate liquidity through our borrowing base and commitments thereunder for the twelve month period following the issuance date of our audited, consolidated financial statements for the fiscal year ended December 31, 2019. As a result, our independent registered public accounting firm included an explanatory paragraph with respect to this uncertainty in its report that is included with our financial statements in this Annual Report on Form 10-K.

Under our Credit Agreement and Term Loan Agreement, we are required to deliver audited, consolidated financial statements without a going concern or like qualification or explanation. Because the audit report prepared by our auditors with respect to the financial statements in this Annual Report on Form 10-K includes an explanatory paragraph expressing uncertainty as to our ability to continue as a going concern, we will be in default under each of the Credit Agreement and Term Loan Agreement on April 14, 2020 when we deliver our financial statements to the lenders under the Credit Agreement and the Term Loan Agreement, respectively. We expect that we will be precluded from drawing additional amounts under the Credit Agreement while the default exists. There is a 30-day grace period related to this covenant in each of the Credit Agreement and the Term Loan Agreement. If we do not obtain a waiver or other suitable relief from the lenders under the Credit Agreement or the Term Loan Agreement before the expiration of the 30-day grace period, an event of default under the Credit Agreement and Term Loan Agreement would occur. At this time, we do not expect to obtain a waiver of this requirement.

If an event of default occurs under our Credit Agreement and Term Loan Agreement, the lenders could accelerate the loans outstanding under the Credit Agreement and Term Loan Agreement. In addition, if the lenders under our Credit Agreement and Term Loan Agreement accelerate the loans outstanding thereunder, we will then also be in default under the indentures related to our Second Lien Notes and our Unsecured Notes. If we default under those indentures, the holders of the Second Lien Notes and Unsecured Notes could accelerate those notes.

If our lenders or our noteholders accelerate the payment of amounts outstanding under the Credit Agreement, Term Loan Agreement, Second Lien Notes, or the Unsecured Notes, respectively, we do not currently have sufficient liquidity to repay such indebtedness and would need additional sources of capital to do so. It is unlikely that we could obtain additional sources of capital from asset sales, public or private issuances of debt, equity or equity-linked securities, debt for equity swaps, or any combination thereof. If we fail to obtain sufficient additional capital to repay the outstanding indebtedness and provide sufficient liquidity to meet our operating needs, it may be necessary for us to seek protection from creditors under Chapter 11 of the United States Bankruptcy Code or the Canadian Bankruptcy and Insolvency Act, or an involuntary petition for bankruptcy may be filed against us in the U.S. or in Canada. Accordingly, there is substantial doubt regarding our

ability to continue as a going concern within one year from the issuance date of our audited, consolidated financial statements for the fiscal year ended December 31, 2019.

We have significant indebtedness. Our level of indebtedness could adversely affect our business, results of operations, and financial condition. If we are unable to comply with the financial and non-financial covenants governing our indebtedness or obtain waivers of any defaults that occur with respect to our indebtedness, or amend, replace or refinance any or all of the agreements governing our indebtedness and/or otherwise secure additional capital, we may be unable to meet our expenses and debt obligations.

As of April 10, 2020, we had the following principal amounts outstanding under our Revolving Credit Facility, our Term Loan Facility (as defined in Note 6), our Second Lien Notes, 2022 Notes and our 2025 Notes:

- \$43.0 million under the Revolving Credit Facility;
- \$966.3 million under the Term Loan Facility;
- \$586.8 million with respect to the Second Lien Notes;
- \$150.4 million with respect to the 2022 Notes; and
- \$225.0 million with respect to the 2025 Notes.

Our indebtedness affects our operations in several ways, including:

- requiring us to dedicate a substantial portion of our cash flow to service our existing debt, thereby reducing the cash available to finance our operations and other business activities, and limiting our flexibility to plan for or react to changes in our business and the industry in which we operate;
- increasing our vulnerability to economic downturns and adverse developments in our business;
- limiting our ability to access the capital markets to raise capital on favorable terms or to obtain additional financing for working capital, capital expenditures or acquisitions or to refinance existing indebtedness;
- placing restrictions on our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations;
- placing us at a competitive disadvantage relative to competitors with lower levels of indebtedness in relation to their overall size or less restrictive terms governing their indebtedness;
- limiting our ability to deduct our net interest expense; and
- making it more difficult for us to satisfy our obligations under our existing indebtedness and increasing the risk that we may default on our debt obligations.

Our ability to meet our expenses and debt service obligations will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. We will not be able to control many of these factors, such as economic conditions and governmental regulation. We depend on our Revolving Credit Facility for future capital and liquidity needs, because we use operating cash flows for investing activities. To the extent future commitments under the Revolving Credit Agreement decrease below the outstanding balance of the Revolving Credit Facility, because of a downward redetermination of the borrowing base and commitments, the Company would be required to enter into a mandatory repayment schedule to satisfy the deficiency. Should the lenders not support such a repayment schedule, intramonth liquidity for the Company could be inadequate to meet obligations on a timely basis. In the event that the borrowing base is reduced to an amount that is less than the outstanding borrowings under the Term Loan Facility, then commitments under the Revolving Credit Facility would be reduced to zero and Ultra Resources would become subject to additional coverage tests under the Term Loan Facility. Among these new requirements is an asset coverage test and, if not satisfied, Ultra Resources would be required to make mandatory prepayments to the lenders under the Term Loan Facility in order to cure any deficiency. Failure to make such required payments would result in an event of default under the Term Loan Facility.

There are covenants in certain agreements governing our indebtedness. In many instances, a default under one of the agreements governing our indebtedness can, if not cured or waived, result in a default under certain of our other indebtedness agreements. A default on our obligations and/or an acceleration of our indebtedness by our lenders or noteholders, as applicable, would have a material adverse impact on our business, financial condition, results of operations, cash flows, and the trading price of our securities.

The Fifth Amendment to the Revolving Credit Facility removed certain financial covenants such that the Company is no longer subject to an interest coverage ratio, a current ratio, a net leverage ratio or an asset coverage ratio. However, the Fifth Amendment to the Revolving Credit Facility introduced a new maximum capital expenditure covenant, which limits the amount of capital expenditures the Company can make per fiscal quarter, subject to certain carry-forward rights for unused amounts.

Additionally, the Sixth Amendment to the Revolving Credit Facility dated February 14, 2020 (i) reduced the excess cash threshold, a part of the anti-cash hoarding provisions, from \$25 million to \$15 million at all times borrowings are outstanding under the Revolving Credit Agreement and (ii) established quarterly borrowing base redeterminations, with the next redetermination occurring on July 1, 2020, and on each October 1, January 1, April 1 and July 1 thereafter.

As previously described, the audit report prepared by our auditors with respect to the financial statements in this Form 10-K includes an explanatory paragraph expressing uncertainty as to our ability to continue as a going concern. Such inclusion is a default under the Credit Agreement and Term Loan Agreement. If our lenders accelerate the payment of amounts outstanding under our Revolving Credit Facility or Term Loan Facility following the expiration of the 30-day grace period, we do not currently have sufficient liquidity to repay such indebtedness and would need additional sources of capital to do so. In addition, the acceleration of the payments outstanding under our Revolving Credit Facility or the Term Loan Facility could result in a cross-default under the indentures governing the Second Lien and Unsecured Notes. We could attempt to obtain additional sources of capital from asset sales, public or private issuances of debt, equity or equity-linked securities, debt for equity swaps, or any combination thereof. However, we cannot provide any assurances that we will be successful in obtaining capital from such transactions on acceptable terms, or at all, and if we were unable to obtain sufficient additional capital to repay the outstanding indebtedness and sufficient liquidity to meet our operating needs, it may be necessary for us to seek protection from creditors under Chapter 11 of the U.S. Bankruptcy Code or the Canadian Bankruptcy and Insolvency Act, or an involuntary petition for bankruptcy may be filed against us in the U.S. or in Canada.

The borrowing base under our Revolving Credit Facility may be reduced, which could limit us in the future and negatively impact our ability to meet our financial obligations.

Based on the Sixth Amendment, the commitment amount under the Revolving Credit Facility was reduced from \$120 million to \$100 million with the associated borrowing base being set at \$1.075 billion, effective April 1, 2020. Under the Sixth Amendment, the borrowing base is redetermined quarterly and the next borrowing base redetermination date is scheduled to be on July 1, 2020. In addition, either we or the lenders may request an interim redetermination twice per 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.

An inadequate borrowing base and/or commitment amount could potentially have an adverse impact on our liquidity and the ability to meet our financial obligations. In the event of a decrease in our borrowing base 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. If we are required to repay the indebtedness under our Revolving Credit Facility as a result of a downward borrowing base redetermination, we may be unable to access the equity or debt capital markets, including the market for senior unsecured notes, at commercially reasonable rates to meet our obligations, including any such debt repayment obligations.

Our common shares were recently delisted from The NASDAQ Global Select Market and trade in an over-the-counter market. This may negatively affect our stock price and liquidity.

As previously disclosed, on August 8, 2019, our common shares were delisted from The NASDAQ Global Select Market. Trading in our common shares is now conducted in the over-the-counter markets on the OTC Bulletin Board and the liquidity of our common shares may likely be reduced or impaired, not only in the number of shares which could be purchased and sold, but also through delays in the timing of the transactions. There may also be a reduction in our coverage by security analysts and the news media, thereby resulting in potential lower prices for our common shares than might otherwise prevail. The delisting of our common shares may also result in other adverse consequences, including lower demand for our shares, adverse publicity and a reduced interest in our Company from investors, analysts and other market participants.

Investments in securities trading on the over-the-counter markets are generally less liquid than investments in securities trading on a national securities exchange. In addition, the trading of our common shares on the over-the-counter markets could have other negative implications, including the potential loss of confidence in us by suppliers, customers and employees and the loss of institutional investor interest in our common shares. This could further depress the trading price of our common shares and could also have a long-term adverse effect on our ability to raise capital.

There can be no assurance that our common shares will continue to trade on the over-the-counter markets or that any public market for the common shares will exist in the future, whether broker-dealers will continue to provide public quotes of the common shares on this market, whether the trading volume of the common shares will be sufficient to provide for an efficient trading market, whether quotes for the common shares may be blocked in the future, or that we will be able to relist the common shares on a national securities exchange. If we fail to remain current in our reporting requirements, the market liquidity of our securities could be harmed by impacting the ability of broker-dealers to trade our securities and the ability of stockholders to sell their securities in the secondary market.

If we cannot obtain sufficient capital when needed, we will not be able to continue with our 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. Further, fluctuations in oil, NGL and natural gas prices can create fiscal challenges for the oil and gas industry. These conditions have impacted companies in the oil and gas industry and the Company's spending and operating plans and may continue to do so in the future. There may be unexpected business impacts from market uncertainty, including volatile changes in currency exchange rates, inflation, interest rates, defaults of suppliers and general levels of investing and consuming activity, as well as a potential impact on the Company's credit ratings, which could

affect its liquidity and general ability to obtain financing. 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 substantial indebtedness, liquidity concerns, the credit ratings assigned to our debt by independent credit rating agencies and historical emergence from bankruptcy in 2017 could adversely affect our business and relationships.

Our substantial indebtedness, liquidity concerns, the credit ratings assigned to our debt by independent credit rating agencies and our historical emergence from Chapter 11 bankruptcy proceedings in 2017 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.

Transfers or issuances of our equity may impair our ability to utilize our U.S. federal net operating losses.

Under U.S. federal income tax law, a corporation is generally permitted to deduct from its taxable income net operating losses (“NOLs”) carried forward from prior years. We have NOL carryforwards of approximately \$2.3 billion as of December 31, 2019. Our ability to utilize our U.S. federal NOL carryforwards to offset future taxable income and to reduce 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 of 1986, as amended (the “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 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. Transfers of our stock and future transactions, including potential equity issuances and liability management efforts could ultimately result in another “ownership change” occurring in the future. Under section 382 of the Code, absent an applicable exception, if a corporation undergoes an “ownership change,” the amount of its pre-“ownership change” NOLs and other tax attributes 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, if we have a so-called “net unrealized built-in gain” in our assets, an additional amount calculated based on certain actual or “deemed” “recognized” “built-in gains” in our assets that occur within a 5-year “recognition period” following an “ownership change.” By contrast, in the event we were to determine that we will have a so-called “net unrealized built-in loss” in our assets at the time an “ownership change” occurs, our “recognized built-in losses” during the 5-year “recognition period” would also become subject limitation. The IRS has proposed regulations that would substantially change the calculations regarding “net unrealized built-in gains,” “recognized built-in gains,” “net unrealized built-in losses,” and “recognized built-in losses” in a way that is highly taxpayer-unfavorable, but we cannot predict when and to what extent those proposed regulations will be finalized. The ownership change that occurred as a result of our exit from chapter 11 proceedings should not materially limit our ability to utilize our NOL carryforwards, but it may be affected by future “ownership changes”. In addition, under the tax reform bill commonly as the Tax Cuts and Jobs Act (the “Tax Act”), which was signed into law on December 22, 2017, (i) the amount of post-2017 NOLs that we are permitted to deduct in any taxable year was generally limited to 80% of our taxable income in such year, where taxable income is determined without regard to the NOL deduction itself, and (ii) post-2017 net operating losses were not able to be carried back to prior taxable years. However, utilization of net operating losses has been temporarily expanded under the Coronavirus Aid, Relief, and Economic Security Act (the “CARES Act”). Under the CARES Act, (i) for taxable years beginning before 2021, NOL carryforwards and NOL carrybacks may offset 100% of taxable income, and (ii) NOLs arising in 2018, 2019, and 2020 taxable years may be carried back to each of the five preceding years to generate a refund. There can be no assurance that we will be able to utilize our U.S. federal income tax NOL carryforwards to offset future taxable income.

Our operations and liquidity could be adversely affected if we fail to maintain required bonds or if surety companies require us to secure such bonds with cash collateral or letters of credit.

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 BLM, (ii) the lack of availability of bonding, higher expense or unfavorable market terms of new bonds; and (iii) 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 already constrained cash flow. In addition, surety companies may require us to post letters of credit or secure bonds with cash collateral as a result of our credit rating, which would adversely affect our liquidity.

Liquidity concerns could result in a downgrade in our debt ratings which could restrict our access to, and negatively impact the terms of, current or future financings or trade credit.

Our ability to obtain financings and trade credit and the terms of any financings or trade credit is, in part, dependent on the credit ratings assigned to our debt by independent credit rating agencies. We cannot provide assurance that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. Factors that may impact our credit ratings include debt levels, planned asset purchases or sales and near-term and long-term production growth opportunities, liquidity, asset quality, cost structure, product mix and commodity pricing levels. A ratings downgrade could adversely impact our ability to access financings or trade credit, increase our borrowing costs and potentially require us to post letters of credit for certain obligations.

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 96% of our total production and 86% of our consolidated revenue for the year ended December 31, 2019 and represented 96% of our total proved reserves as of December 31, 2019. 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 4% of our total production and 13% of our consolidated revenue for the year ended December 31, 2019 and represented 4% of our total proved reserves as of December 31, 2019. 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.

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 continue indefinitely, and may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations, our debt repayment and service obligations, and our 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 and we expect this volatility to continue for the foreseeable future. For example, during the period from January 1, 2014 to December 31, 2019, the Calendar month average of NYMEX West Texas Intermediate oil prices ranged from a high of \$105.15 per Bbl to a low of \$30.62 per Bbl. NYMEX Natural Gas settlement prices have ranged from a high of \$5.56 per MMBtu to a low of \$1.71 per MMBtu during the same period. Additionally, the price differential for natural gas can also vary significantly. Over this same period, monthly prices for NwRox ranged from a high of \$5.70 per MMBtu to a low of \$1.51 per MMBtu. This near-term volatility may affect future prices in 2020 and beyond. The volatility of the energy markets makes it difficult to predict future oil and natural gas price movements with any certainty.

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 ("OPEC");
- 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;
- government policies to discourage use of fuels that emit “greenhouse gases” (“GHGs”) and encourage use of alternative energy;
- 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;
- the availability of drilling rigs and completion equipment; and
- the overall economic environment.

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 remain at current levels or 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), participation of joint working interest owners on projects, 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.

Our producing properties are located in the Green River Basin in southwest Wyoming, making us vulnerable to risks associated with operating in a single geographic area.

All of our producing properties are geographically concentrated in the Green River Basin in southwest Wyoming. At December 31, 2019, all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we are disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, availability of equipment and personnel, water shortages or other drought-related conditions or interruption of the processing or transportation of oil, natural gas or NGLs.

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 attract and 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.

Our business relies on certain key personnel.

Our management believes that our continued success will depend to a significant extent upon the efforts and abilities of certain of our key personnel. The loss of the services of any of these key personnel could have a material adverse effect on our business. We do not maintain “key man” life insurance on any of our officers or other employees.

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

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. We pay royalties and taxes based on physical production; therefore, if we have utilized derivative transactions on a high percentage of our forecast production, we may have royalty and tax burdens that are significantly higher than the derivative price settled for that month’s production.

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”) 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 has 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 those position limits, provided that such hedging transactions satisfy the CFTC’s requirements for “bona fide hedging” transactions.

While it is not possible at this time to predict when the CFTC will issue final rules applicable to position limits, 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 in connection with our financial derivative activities. The full impact of the Dodd-Frank Act’s swap regulatory provisions and the related rules of the CFTC on our business will not be known until all of the rules to be adopted under the Dodd-Frank Act have been adopted and fully implemented and the market for derivatives contracts has adjusted. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts, 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 occupational safety and health aspects of our operations and protection of the environment. 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 liability for the investigation, removal or remediation of previously released materials or property contamination. Liability may be imposed 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 curtail or 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 these changes could 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. Any such changes could require significant expenditures by the Company 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 the Company or such other operators. The oil and natural gas industry faced increased scrutiny as a result of the FY 2017-2019 National Enforcement Initiatives (“NEI”) promulgated by the EPA, through which the EPA purportedly sought to 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. However, in June 2019, EPA proposed to transition its focus to significant public health and environmental problems without regard to sector, renaming the NEI program and issuing the FY 2020-2023 National Compliance Initiatives, thereby discontinuing the energy extraction activities NEI. Government disruptions, such as an extended federal government shutdown resulting from the failure to pass budget appropriations, adopt continuing funding resolutions or raise the debt ceiling, could delay or halt the granting and renewal of such permits, approvals, and certificates required to conduct our operations.

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 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 requires the permitting of GHG emissions for certain sources that require permits 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 and VOC from new, modified or reconstructed sources in the oil and natural gas sector; however, in September 2018, under a new administration, the EPA proposed amendments that would relax requirements of the rules. In August 2019, the EPA proposed a significant rollback to the 2016 rule that, if finalized, would rescind the VOC and methane requirements applicable to transmission and storage sources and the methane requirements for production and processing sources, or in the alternative, rescind methane requirements applicable to all oil and natural gas sources. Additionally, in September 2018, the BLM issued a rule that relaxes or rescinds certain requirements of regulations it previously enacted to reduce methane emissions from venting, flaring, and leaks during oil and gas operations on public lands; California and New Mexico have challenged the new rule in ongoing litigation. In addition, in April 2018, a coalition of states filed a lawsuit in federal district court aiming to force the EPA to establish guidelines for limiting methane emissions from existing sources in the oil and natural gas sector; that lawsuit is pending (as of October 2019, the EPA had requested a stay of the litigation pending its proposed overhaul of the 2016 methane requirements). Several states are pursuing similar measures to regulate emissions of methane from new and existing sources within the oil and natural gas source category.

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. In addition, there are Congressional proposals that could result in significant curtailment of oil and natural gas development and production, and hydraulic fracturing in particular, on BLM lands, where we hold considerable acreage. 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 if, how or when the United States or 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.

Moreover, incentives to conserve energy, reduce greenhouse gas emissions in product supply chains, or use alternative energy sources as a means of addressing climate change could reduce demand for the oil and natural gas we produce. In addition, parties concerned about the potential effects of climate change have directed their attention at sources of funding for energy companies, which has resulted in certain financial institutions, funds and other sources of capital, restricting or eliminating their investment in or lending to oil and natural gas activities. Finally, growing attention to climate change risks has resulted in increased likelihood of governmental investigations and private litigation, which could increase our costs or otherwise adversely affect our business.

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.

Most scientists have concluded that increasing concentrations of GHG in the atmosphere may produce significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climate events, that could have an adverse effect on our operators' operations and the production on our properties. 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 coverage 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, suppliers, or customers 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 and state legislative and regulatory initiatives relating to hydraulic fracturing, including with respect to water use and waste disposal, 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, the EPA has taken certain actions with respect to regulating hydraulic fracturing. For example, the 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 governing performance standards for the oil and natural gas industry, for which the EPA in August 2019 has proposed amendments that would rescind certain requirements of the regulations; 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 established new or more stringent standards for performing hydraulic fracturing on federal and Indian lands. However, following years of litigation, the BLM rescinded the rule in December 2017; a lawsuit challenging the rule rescission is pending. The BLM also issued 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. The BLM also issued rules in November 2016 to limit methane emissions from new and existing oil and gas operations on federal lands, but subsequently relaxed and rescinded certain requirements of the rules in September 2018; a lawsuit challenging the September 2018 rule revision is pending.

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. 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.

In addition, hydraulic fracturing operations require the use of a significant amount of water. The inability to locate sufficient amounts of water, or dispose of or recycle water used in drilling and production operations, could adversely impact our operations. Moreover, new environmental initiatives and regulations could include restrictions on the ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the development or production of natural gas.

Finally, in some instances, the operation of underground injection wells for the disposal of waste has been alleged to cause earthquakes. In Oklahoma, for example, such issues have led to orders prohibiting continued injection or the suspension of drilling in certain wells identified as possible sources of seismic activity. Such concerns also have resulted in stricter regulatory requirements in some jurisdictions relating to the location and operation of underground injection wells. Although our operations are not located in those jurisdictions, any future orders or regulations addressing concerns about seismic activity from well injection in jurisdictions where we operate could affect our operations.

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. In past years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. tax laws, including certain key U.S. federal income tax provisions currently available to oil and gas companies. Such legislative changes have included, but not been limited to, (i) the repeal of the percentage depletion allowance for natural gas and oil properties, (ii) the elimination of current deductions for intangible drilling and development costs, and (iii) an extension of the amortization period for certain geological and geophysical expenditures. Although these provisions were largely unchanged in the Tax Act, and the CARES Act, and could include, some or all of these proposals as part of future tax reform legislation. Moreover, other more general features of any additional tax reform legislation, including changes to cost recovery rules, may be developed that also would change the taxation of oil and gas companies. It is unclear whether these or similar changes will be enacted in future legislation and, if enacted, how soon any such changes could take effect. 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 or timing of payments that we are obligated to make, either of which could adversely affect our business, financial condition, and operating results.

On March 27, 2020, President Trump signed into U.S. federal law the CARES Act, which is aimed at providing emergency assistance and health care for individuals, families, and businesses affected by the COVID-19 pandemic and generally supporting the U.S. economy. The CARES Act, among other things, includes provisions relating to refundable payroll tax credits, deferment of employer side social security

payments, net operating loss carryback periods, alternative minimum tax credit refunds, modifications to the net interest deduction limitations and technical corrections to tax depreciation methods for qualified improvement property. In particular, under the CARES Act, (i) for taxable years beginning before 2021, net operating loss carryforwards and carrybacks may offset 100% of taxable income, (ii) NOLs arising in 2018, 2019, and 2020 taxable years may be carried back to each of the preceding five years to generate a refund and (iii) for taxable years beginning in 2019 and 2020, the base for interest deductibility is increased from 30% to 50% of EBITDA. We are analyzing the different aspects of the CARES Act to determine whether any specific provisions may impact 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, including technologies operated by or under the control of third parties, 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 (or the loss of Company 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 shares. 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.

Concerns over general economic, business or industry conditions may have a material adverse effect on our results of operations, financial condition and cash available for distribution.

Concerns over global economic conditions, energy costs, geopolitical issues, inflation, the availability and cost of credit in the European, Asian and the U.S. markets contribute to economic uncertainty and diminished expectations for the global economy. These factors, combined with volatile prices of oil, NGL and natural gas, volatility in consumer confidence and job markets, may result in an economic slowdown or recession. In addition, continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the economies of the United States and other countries. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates, worldwide demand for petroleum products could diminish, which could impact the price at which oil, NGL and natural gas from our properties are sold, affect the ability of vendors, suppliers and customers associated with our properties to continue operations and ultimately adversely impact our results of operations, financial condition and cash available for distribution.

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.

Outbreaks of communicable diseases could adversely affect our business, financial condition and results of operations.

Global or national health concerns, including the outbreak of pandemic or contagious disease, can negatively impact the global economy and, therefore, demand and pricing for oil and natural gas products. For example, there have been recent outbreaks on a global basis, including in the United States, of COVID-19. The outbreak of communicable diseases, or the perception that such an outbreak could occur, could result in a widespread public health crisis that could adversely affect the economies and financial markets of many countries, resulting in an economic downturn that would negatively impact the demand for oil and natural gas products. Furthermore, uncertainty regarding the impact of any outbreak of pandemic or contagious disease, including COVID-19, could lead to increased volatility in oil and natural gas prices. Additionally,

if a pandemic or epidemic, including COVID-19, were to impact a location where we have a high concentration of our business and resources, the workforce we depend on could be affected by such occurrence, which could also significantly disrupt our results of operations. The duration of such a disruption and the related financial impact from COVID-19 and other such pandemics cannot be reasonably estimated at this time. The occurrence or continuation of any of these events could lead to decreased revenues and limit our ability to execute on our business plan, which could adversely affect our business, financial condition and results of operations.

The ability or willingness of OPEC and other oil exporting nations to set and maintain production levels has a significant impact on oil and natural gas commodity prices.

OPEC is an intergovernmental organization that seeks to manage the price and supply of oil on the global energy market. Actions taken by OPEC members, including those taken alongside other oil exporting nations, have a significant impact on global oil supply and pricing. For example, OPEC and certain other oil exporting nations have previously agreed to take measures, including production cuts, to support crude oil prices. In March 2020, members of OPEC and Russia considered extending and potentially increasing these oil production cuts. However, these negotiations were unsuccessful. As a result, Saudi Arabia announced an immediate reduction in export prices and Russia announced that all previously agreed oil production cuts will expire on April 1, 2020. These actions led to an immediate and steep decrease in oil prices. There can be no assurance that OPEC members and other oil exporting nations will agree to future production cuts or other actions to support and stabilize oil prices, nor can there be any assurance that they will not further reduce oil prices or increase production. Uncertainty regarding future actions to be taken by OPEC members or other oil exporting countries could lead to increased volatility in the price of oil, which could adversely affect our business, financial condition and results of operations.

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. As we assess our business operations in light of our need for liquidity and the current natural gas price environment, we currently have no immediate plans to drill additional wells in our leasehold position in the Green River Basin in southwest Wyoming. This suspension of drilling activity will lead to a decline in our reserves as has been evidenced by our decision to suspend drilling operations in September 2019, due to the low commodity price environment and the expected investment returns in the current commodity price environment. We can give no assurance that we will be able to find, develop or acquire additional reserves at acceptable costs or at all.

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 resume 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 Part II, 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 and cash on hand to fund our capital budget, our operating costs and our interest service obligations during 2020. The loan commitment and the aggregate amount of money that we can borrow under the Revolving Credit Facility 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 Part II, 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 exclusively 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 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.

Conservation measures and improvements in or new discoveries of alternative 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 fuel conservation measures, improvement in or new discoveries of alternative energy, transportation, or materials technologies and increasing consumer demand for alternatives to oil and natural gas that increase the use of alternative forms of energy and alternative feedstocks, 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.

A negative shift in investor sentiment of the oil and gas industry could adversely affect our ability to raise debt and equity capital.

Certain segments of the investor community have developed negative sentiment towards investing in our industry. Recent equity returns in the sector versus other industry sectors have led to lower oil and gas representation in certain key equity market indices. In addition, some investors, including investment advisors and certain sovereign wealth, pension funds, university endowments and family foundations, have stated policies to disinvest in the oil and gas sector based on their social and environmental considerations. Certain other stakeholders have also pressured commercial and investment banks to stop financing oil and gas and related infrastructure projects.

Such developments, including environmental activism and initiatives aimed at limiting climate change and reducing air pollution, could result in downward pressure on the stock prices of oil and gas companies, including ours. This may also potentially result in a reduction of available capital funding for potential development projects, impacting our future financial results.

Negative public perception regarding us and/or our industry could have an adverse effect on our operations.

Negative public perception regarding us and/or our industry resulting from, among other things, concerns raised by advocacy groups about hydraulic fracturing, waste disposal, oil spills, seismic activity, climate change, explosions of natural gas transmission lines and the development and operation of pipelines and other midstream facilities may lead to increased regulatory scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. Additionally, environmental groups, landowners, local groups and other advocates may oppose our operations through organized protests, attempts to block or sabotage our operations or those of our midstream transportation providers, intervene in regulatory or administrative proceedings involving our assets or those of our midstream transportation providers, or file lawsuits or other actions designed to prevent, disrupt or delay the development or operation of our assets and business or those of our midstream transportation providers. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we require to conduct our operations to be withheld, delayed or burdened by requirements that restrict our ability to profitably conduct our business.

Recently, activists concerned about the potential effects of climate change have directed their attention towards sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in energy-related activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities.

A low ESG or sustainability score could result in the exclusion of our common shares from consideration by certain investment funds and a negative perception of us by certain investors.

Certain organizations that provide corporate governance and other corporate risk information to investors and shareholders have developed scores and ratings to evaluate companies and investment funds based upon environmental, social and governance (“ESG”) or “sustainability” metrics. Currently, there are no universal standards for such scores or ratings, but the importance of sustainability evaluations is becoming more broadly accepted by investors and shareholders. Many investment funds focus on positive ESG business practices and sustainability scores when making investments. In addition, investors, particularly institutional investors, use these scores to benchmark companies against their peers and if a company is perceived as lagging, these investors may engage with companies to require improved ESG disclosure or performance. Moreover, certain members of the broader investment community may consider a company’s sustainability score as a reputational or other factor in making an investment decision. Consequently, a low sustainability score could result in exclusion of the Company’s common shares from consideration by certain investment funds, engagement by investors seeking to improve such scores and a negative perception of the Company by certain investors.

Damage to our reputation could damage our business.

Our reputation is a critical factor in our relationships with employees, investors, customers, suppliers and joint venture partners. If we fail to address, or appear to fail to address, issues that give rise to reputational risk, including those described throughout this “Risk Factors” section, we could significantly harm our reputation. Our reputation may also be damaged by how we respond to corporate crises. Corporate crises can arise from catastrophic events as well as from incidents involving unethical behavior or misconduct; allegations of legal noncompliance; internal control failures; corporate governance issues; data breaches; workplace safety incidents; environmental incidents; media statements; the conduct of our suppliers or representatives; and other issues or incidents that, whether actual or perceived, result in adverse publicity. If we fail to respond quickly and effectively to address such crises, the ensuing negative public reaction could significantly harm our reputation and could lead to increases in litigation claims and asserted damages or subject us to regulatory actions or restrictions.

Damage to our reputation could negatively affect the demand for our services and consequently, have a material adverse effect on our business, financial condition, and results of operations. It could also reduce investor confidence in us, adversely affecting our stock price. Moreover, repairing our reputation may be difficult, time-consuming and expensive.

We are a smaller reporting company, and we cannot be certain if the reduced disclosure requirements applicable to smaller reporting companies will make our common stock less attractive to investors.

We are currently a “smaller reporting company,” meaning that we are not an investment company, an asset-backed issuer, or a majority-owned subsidiary of a parent company that is not a smaller reporting company and have a non-affiliated public float of less than \$250 million or annual revenues of less than \$100 million and public float of less than \$700 million during the most recently completed fiscal year. At such time as we cease being a “smaller reporting company,” we will be required to provide additional disclosure in our SEC filings. “Smaller reporting companies” are able to provide simplified disclosures in their filings, including with respect to, among other things, executive compensation and financial statement information and are also exempt from certain provisions of the Sarbanes-Oxley Act which may make it harder for investors to analyze our results of operations and financial prospects.

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 (the “Securities Act”), Section 21E of the Exchange Act, 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 vertical and horizontal wells;
- the timing and amount of future production and operating costs;
- our ability to respond to low natural gas prices;
- our levels of indebtedness
- 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 or following the recent default under the terms of our Credit Agreement and Term Loan Agreement resulting from the going concern qualification to our audited, consolidated financial statements in this Form 10-K;
- 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;
- the uncertainty of estimates of oil and natural gas reserves such that our estimates of oil and natural gas reserve quantities, and the discounted present value of those reserves may change for a variety of reason including but not limited to changes in prices, costs, estimated decline curves, among other circumstances;
- our ability to restructure our balance sheet in a manner that allows us to continue as a going concern over the long term;
- changes in taxation laws in local and state jurisdictions;

- any future global economic downturn;
- the impact of outbreaks of communicable diseases such as the novel highly transmissible and pathogenic coronavirus (“COVID-19”) on business activity, the Company’s operations and national and global economic conditions, generally;
- the willingness of the Organization of Petroleum Exporting Countries (“OPEC”) to set and maintain production levels;
- 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 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;
- the impact of our shares trading on the OTC Bulletin Board;
- our ability to maintain the listing of our common shares on The OTCQX tier of the OTC Bulletin Board;
- changes in customer demand and producers’ supply;
- the uncertainty of our ability to attract capital and obtain financing on favorable terms;
- negative shifts in investor sentiment of the oil and gas industry;
- negative public perception regarding us and/or our industry;
- 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. 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 Company previously owned oil and natural gas leases in Utah and Pennsylvania, which the Company sold in September 2018 and December 2017, respectively.

Due to the cessation of the drilling program, the Company has no estimated PUD reserves as of December 31, 2019, with respect to its properties because it has elected not to drill new wells in the current commodity price environment. Additionally, as noted below, the Company’s has a \$5 million limitation of capital expenditures per quarter as set forth in the Fifth Amendment to the Credit Agreement. The Company previously reported estimated PUD reserves in SEC filings, and, if in the future we can satisfy the reasonable certainty criteria as prescribed under the SEC requirements, we would likely record and report estimated PUD reserves in future filings.

Green River Basin, Wyoming

Acreage. As of December 31, 2019, the Company owned oil and natural gas leases totaling approximately 117,000 gross (83,000 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, 2019, approximately 45,000 gross (30,000 net) acres were developed, and 72,000 gross (53,000 net) acres

were undeveloped. The developed and undeveloped portion represents 100% of the Company's total developed and undeveloped net acreage. The Company operates 92% of its production in the Pinedale field.

Lease maintenance costs in Wyoming were approximately \$0.7 million for the year ended December 31, 2019. The Company currently owns 51 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 2019, the Company participated in the drilling of 64.0 gross (51.0 net) productive development wells on the Green River Basin properties. At December 31, 2019, the Company did not have any additional development wells that commenced during the year and were either still drilling or had operations suspended at a depth short of total depth.

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 2019, the Company participated in the drilling of a total of 20.0 gross (20.0 net) productive exploratory wells on the Green River Basin properties. At December 31, 2019, there were 9.0 gross (3.8 net) exploratory wells which were suspended at a depth short of total depth and thus a determination of productive capability could not be made at year-end.

Seismic Activity. The Company owns 492 square miles of 3D seismic data in Wyoming which provides 455 square miles of coverage of the entire Pinedale Anticline and most of Jonah field. The data consists of proprietary data and data licensed from seismic contractors. During 2019, the Company completed a 40 square mile seismic inversion project to enhance the resolution and illuminate the sandstones in the Lower Lance and Mesaverde in the southern Anticline area to assist with future wellbore targeting. The Company also completed a 95 square mile 3D structural reconstruction study of the middle portion of the Pinedale Anticline that elucidates the geological structural history, trapping geometry, and fluid migration to explain variations in hydrocarbon accumulation and assist with future well planning.

Divested Assets

Uinta Basin, Utah. During the third quarter 2018, the Company sold the oil and gas properties covering approximately 8,300 gross (7,800 net) acres in the Uinta Basin in Utah for net cash proceeds of \$69.3 million, including transaction fees of \$0.6 million. This acreage is located in Uintah County in the eastern portion of the Uinta Basin.

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.

Oil and Gas Reserves

The following table sets forth the Company's quantities of proved reserves for the years ended December 31, 2019, 2018 and 2017. The reserve estimates were prepared by Netherland, Sewell & Associates, Inc. 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, 2019, 2018 and 2017.

In 2017, the Company renegotiated its existing gas processing contracts in Wyoming. These 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 Company's internal controls for booking PUD reserves include testing whether the Company has the intent and financial capability to execute PUD drilling. During 2019, the Company decided to suspend its operated drilling program in the Pinedale field. This decision was based on natural gas pricing remaining near multi-year lows. As such, the Company lacks the required degree of certainty of our ability commit resources to fund the drilling of new wells in our five-year development program. As a result, we did not record any PUD reserves in the December 31, 2019 reserve report. As of December 31, 2018 and 2017, proved undeveloped reserves represented 23% of the Company's total proved reserves.

	December 31,		
	2019	2018	2017
	(\$ amounts in thousands, except per unit data)		
Proved Developed Reserves			
Natural gas (MMcf)	1,902,600	2,243,956	2,261,289
Oil (MBbl)	14,627	17,876	21,652
Natural gas liquids (MBbl)	—	—	71
Proved Undeveloped Reserves			
Natural gas (MMcf)	—	677,877	694,703
Oil (MBbl)	—	5,569	5,466
Natural gas liquids (MBbl)	—	—	—
Total Proved Reserves (MMcfe) (1)	1,990,362	3,062,503	3,119,126
Estimated future net cash flows, before income tax	\$ 2,904,393	\$ 4,724,843	\$ 4,377,344
Discounted future net cash flows, before income taxes (2)	\$ 1,710,619	\$ 2,435,356	\$ 2,384,328
Future income tax (discounted)	\$ —	\$ (29,873)	\$ —
Standardized measure of discounted future net cash flows, after income tax	\$ 1,710,619	\$ 2,405,483	\$ 2,384,328
Calculated average price (3)			
Gas (\$/Mcf)	\$ 2.44	\$ 2.59	\$ 2.59
Oil (\$/Bbl)	\$ 55.36	\$ 63.49	\$ 48.05
NGLs (\$/Bbl)	\$ —	\$ —	\$ 26.85

- (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 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, 2019, 2018 and 2017, reflect reference pricing based on the average of the monthly 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

As previously mentioned, the Company did not include PUD reserves in its total proved reserve estimates as of December 31, 2019 due to its decision to suspend its operated drilling program.

Development plan: The development plan underlying the Company’s PUD reserves, if any, is based on the best information available at the time of adoption. Factors, such as commodity price, service costs, performance data, and asset mix, are subject to change; therefore, the Company occasionally revises its development plan. Development plan revisions include deferrals, removals, and substitutions of previously scheduled PUD reserve locations.

As commodity prices fell during 2019, management and the Board revised the development plan and decreased the development pace. Over the course of 2019, we decreased our drilling program reducing the number of rigs deployed in development from three to two, then to one, and ultimately to zero. Despite the reduction of activity, the Company’s PUD conversion rate was 19.8% in 2019.

In addition, as a part of our internal controls for determining a plan to develop our proved reserves each year, we consider whether we have the intent and financial capability to develop PUD reserves. This year, because of the natural gas price environment and the projected investment returns, we lack the required degree of certainty that we have the ability to fund a development plan. Therefore, as of December 31, 2019, we transferred all of our PUD reserves to unproved status. We anticipate reporting PUD reserves in future filings, if we determine that we have the intent and financial capability to execute a development plan.

Changes in proved undeveloped reserves: The Company annually reviews all PUD reserves to ensure an appropriate plan for development exists. Changes to the Company's PUD reserves during 2019 are summarized in the table below. These changes include updates to prior PUD reserves, the transfer and revision of PUD reserves to unproved categories due to development plan changes, and the impact of changes in economic conditions, including changes in commodity prices.

	MMcfe
Proved undeveloped reserves, December 31, 2018	711,293
Converted to proved developed	(140,929)
Proved undeveloped reserve extensions	—
Proved undeveloped reserve purchased	—
Proved undeveloped reserve revisions	(570,364)
Proved undeveloped reserves, December 31, 2019	—

Conversions: In 2019, the conversion rate was 19.8% based on PUD reserves recorded as of December 31, 2018.

Additions/Extensions: At December 31, 2019, the Company did not book any PUD reserves. Accordingly, there were no additions to the PUD reserve category.

Purchases: In 2019, there were no purchases related to PUD reserves.

Revisions: At December 31, 2019, the Company transferred approximately 570 Bcfe of PUD reserves to unproved categories. Due to management's decision to suspend its operated drilling program during 2019, we concluded we lacked the required degree of certainty about our financial capability to fund a development program and the availability of capital that would be required to develop PUD reserves.

March 2020 Reserves:

Impairment of Oil and Gas Properties in the Quarter Ended March 31, 2020

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.

In order to fulfill its obligation to evaluate the full cost ceiling evaluation and to calculate DD&A of its oil and gas properties, the Company is required to estimate its reserves on a quarterly basis. The estimated proven oil and gas reserves considers the estimated future production based on the most current well information available including decline rate changes causing downward revisions and updated pricing in accordance with SEC requirements. The reserves estimated as of March 31, 2020 were prepared by Netherland, Sewell & Associates, Inc. The comparable calculated average prices utilized in the preparation of the reserves as of March 31, 2020 were \$2.07 per Mcf and \$55.35 per Bbl. These prices represent a decrease of 15% and <1% for natural gas and oil, respectively, as compared to the pricing utilized as of December 31, 2019.

The reserve estimates as of March 31, 2020 are as follow:

	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas Equivalents (MMcfe)
Developed	1,694,828	11,902	1,766,239
Undeveloped	—	—	—
Total Proved as of March 31, 2020	1,694,828	11,902	1,766,239

The future net cash flows, before income tax and the discounted future net cash flows before income tax estimated at March 31, 2020 were \$1.907 billion and \$1.218 billion, respectively. As a result of the decrease in both quantities of oil and gas reserves, as well as the discounted future cash flow estimates, the Company estimates it will record an increased rate of DD&A per Mcfe and require a material impairment charge to its oil and gas properties due to the ceiling test limitation in the quarter ended March 31, 2020.

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 with GAAP. Our Director of Reservoir and Development is primarily responsible for overseeing the preparation of the Company's reserve estimates and has a Bachelor of Science degree in Petroleum Engineering 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 PUD 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, 2019 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 period ended March 31, 2020 and the years ended December 31, 2019, 2018 and 2017, which are included in this annual report.

The reserves estimates shown herein have been independently evaluated by 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 eight 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 15 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

Our internal professional staff works closely with 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 NSAI reports are included as Exhibits 99.1 and 99.2 to this annual report.

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,		
	2019	2018	2017
	(In thousands, except per unit data)		
Production			
Natural gas (Mcf)	230,121	260,406	260,009
Oil (Bbl)	1,683	2,442	2,775
Total (Mcfe)	240,219	275,058	276,659
Revenues			
Natural gas sales	\$ 637,007	\$ 722,313	\$ 748,682
Oil sales	97,231	153,534	133,368
Other revenues	7,794	16,652	9,823
Total revenues	\$ 742,032	\$ 892,499	\$ 891,873
Lease Operating Expenses			
Lease operating expenses (1)	\$ 70,608	\$ 90,290	\$ 92,326
Facility lease expense	25,468	25,947	21,749
Production taxes	79,459	93,322	91,067
Gathering	78,261	89,294	87,287
Transportation charges	1,496	512	(334)
Total lease operating expenses	\$ 255,292	\$ 299,365	\$ 292,095
Average Realized Prices			
Natural gas (\$/Mcf, including realized gains (losses) on commodity derivatives)	\$ 2.50	\$ 2.48	\$ 2.92
Natural gas (\$/Mcf, excluding realized gains (losses) on commodity derivatives)	\$ 2.77	\$ 2.77	\$ 2.88
Oil (\$/Bbl, including realized gains (losses) on commodity derivatives)	\$ 59.97	\$ 59.44	\$ 48.05
Oil (\$/Bbl, excluding realized gains (losses) on commodity derivatives)	\$ 57.78	\$ 62.88	\$ 48.05
Average Costs per Mcfe			
Lease operating expenses	\$ 0.29	\$ 0.33	\$ 0.33
Facility lease expense	0.11	0.09	0.08
Production taxes	0.33	0.34	0.33
Gathering	0.33	0.33	0.31
Transportation charges	0.01	-	-
DD&A	0.85	0.74	0.59
General & administrative	0.11	0.09	0.14
Interest	0.54	0.54	1.31
Total costs per Mcfe	\$ 2.57	\$ 2.46	\$ 3.09

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

The following table sets forth the net sales volumes, operating expenses and average realized natural gas prices attributable to the Pinedale field, which is the only field that contained 15% or more of our total estimated proved reserves for each year:

	Year ended December 31,		
	2019	2018	2017
	(In thousands)		
Pinedale Field:			
Production (Mcf)	237,851	264,786	256,695
Operating expenses	\$ 252,165	\$ 282,376	\$ 265,051
Average realized price (\$/Mcf excluding realized gains (losses) on commodity derivatives)	\$ 2.77	\$ 2.78	\$ 2.90
Average realized price (\$/Mcf including realized gains (losses) on commodity derivatives)	\$ 2.49	\$ 2.48	\$ 2.95

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. 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 Part I. 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, 2019, the Company's total gross and net wells were as follows:

	Gross Wells	Net Wells
Productive Wells*		
Operated	2,265	1,943
Operated by others	854	241
Total productive wells	3,119	2,183

* 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 risk of remaining terms of its leases are material. The Company expects to maintain essentially all 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. As of December 31, 2019, the Company estimates that approximately 6,300 net leased acres may expire in 2020 through 2022, and approximately 7,200 net leased acres in Wyoming may expire in 2023 through 2029.

As of December 31, 2019, 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	45,000	30,000	72,000	53,000

Drilling Activities

The number of gross and net wells drilled by the Company during each of the three fiscal years ended December 31, 2019, 2018 and 2017 are reflected in the tables below. The well counts in these tables represent classification and costs specific to the reserves deemed to be proved or unproved. Such wells may be completed and turned into sales during different period.

Wyoming — Green River Basin

	2019		2018		2017	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	64.0	51.0	107.0	80.7	—	—
Dry	—	—	—	—	—	—
Total	<u>64.0</u>	<u>51.0</u>	<u>107.0</u>	<u>80.7</u>	<u>—</u>	<u>—</u>
	2019		2018		2017	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Productive	20.0	20.0	28.0	19.8	210.0	172.1
Dry	—	—	—	—	—	—
Total	<u>20.0</u>	<u>20.0</u>	<u>28.0</u>	<u>19.8</u>	<u>210.0</u>	<u>172.1</u>

At December 31, 2019, there were 9.0 gross (3.8 net) exploratory wells which were suspended at a depth short of total depth and thus a determination of productive capability could not be made at year-end.

Utah

The Company divested its Utah assets during the third quarter of 2018. For the years ended December 31, 2018 and 2017, the Company did not drill any development or exploratory wells on its Utah acreage.

Pennsylvania

The Company divested its Pennsylvania assets during the fourth quarter of 2017. For the years ended December 31, 2017, 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 2019, 2018 or 2017. In 2014, the Company sold the surface rights to its Colorado undeveloped acreage and retained some oil and gas mineral rights. The Company no longer owns any leased acreage in Colorado and has no immediate plans for further exploration in Colorado during 2020.

Item 3. Legal Proceedings.

See Note 14 for 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.

The Company's common shares are traded on the OTCQX marketplace under the symbol "UPLC". As of March 31, 2020, there were approximately 313 holders of record of the common shares.

Dividends

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 Credit Agreement, Term Loan Agreement, and the Second Lien Indenture (as 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 oil and gas properties.

Unregistered Sales of Equity Securities

Purchases of Equity Securities by Issuer

The following table provides information about purchases made by the Company (as defined in Rule 10b-18(a)(3) under the Exchange Act) during the twelve months ended December 31, 2019, of shares of common stock, which is the sole class of equity securities registered by the Company pursuant to Section 12 of the Exchange Act:

Period	Total Number of Shares Purchased (1)	Weighted Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Maximum Number of Shares that May Yet Be Purchased Under the Program
January 2019	—	—	—	—
February 2019	—	—	—	—
March 2019	—	—	—	—
April 2019	—	—	—	—
May 2019	190,872	0.39	—	—
June 2019	—	—	—	—
July 2019	—	—	—	—
August 2019	—	—	—	—
September 2019	—	—	—	—
October 2019	—	—	—	—
November 2019	19,759	0.20	—	—
December 2019	—	—	—	—
Total	210,631			

- (1) All shares purchased by the Company in 2019 were surrendered by employees in exchange for the payment of tax withholding upon the vesting of restricted stock awards. The acquisition of the surrendered shares was not part of a publicly announced program to repurchase shares of our common stock.

Warrants

On December 21, 2018, the Company completed the 2018 Exchange Transaction (as defined below), pursuant to which the exchanging noteholders exchanged (i) \$505 million aggregate principal amount, or 72.1%, of the issued and outstanding 2022 Notes and (ii) \$275 million aggregate principal amount, or 55.0%, of the issued and outstanding 2025 Notes for (a) \$545.0 million aggregate principal amount of Second Lien Notes of Ultra Resources and (b) an aggregate of 10,919,499 new warrants of the Company each entitling the holder thereof to purchase one common share of the Company (each a "Warrant" and, collectively, the "Warrants"). See to Item 7. "Management's Discussion and Analysis", for additional details regarding the Exchange Transaction.

Each Warrant is initially exercisable for one common share of the Company at an initial exercise price of \$0.01 per Warrant. No Warrants will be exercisable until the date on which the volume-weighted average price of the Company's common shares is at least \$2.50 per common share for 30 consecutive trading days (the "Trading Price Condition"). Subject to the Trading Price Condition, the Warrants are exercisable at the option of the holders thereof from December 21, 2018 until July 14, 2025, at which time all unexercised Warrants will expire and the rights of the holders of such Warrants to purchase common shares will terminate.

The Warrants issued in the Exchange Transaction were offered and sold pursuant to the exemption provided by Section 4(a)(2) of the Securities Act. This offer was made by the Company to a limited number of persons, each of which is an accredited investor (within the meaning of Rule 501 promulgated under the Securities Act).

Securities Authorized for Issuance Under Equity Compensation Plans

Information about securities authorized for issuance under our equity compensation plan is incorporated herein by reference to Item 12 of Part III of this Annual Report on Form 10-K.

Item 6.Selected Financial Data.

The selected consolidated financial information presented below as of the dates or for the years indicated is derived from the Consolidated Financial Statements of the Company.

	For the Year Ended December 31,				
	2019	2018	2017	2016	2015
(In thousands, except per share data)					
Statement of Operations Data:					
Revenues:					
Natural gas sales	\$ 637,007	\$ 722,313	\$ 748,682	\$ 609,756	\$ 696,730
Oil sales	97,231	153,534	133,368	111,335	142,381
Other revenues	7,794	16,652	9,823	—	—
Total operating revenues	742,032	892,499	891,873	721,091	839,111
Expenses:					
Production expenses and taxes	253,796	298,853	292,429	266,366	288,231
Transportation charges	1,496	512	(334)	20,049	83,803
Depletion, depreciation and amortization	204,227	204,255	161,945	125,121	401,200
Ceiling test and other impairments	—	—	—	—	3,144,899
General and administrative	26,551	25,005	39,548	9,179	7,387
Other operating expenses, net	28,889	9,118	—	—	—
Total operating expenses	514,959	537,743	493,588	420,715	3,925,520
Other:					
Interest expense	(129,398)	(148,316)	(361,367)	(66,565)	(171,918)
Gain (loss) on commodity derivatives	(4,597)	(145,212)	28,412	—	42,611
Deferred gain on sale of liquids gathering system	—	10,553	10,553	10,553	10,553
Contract settlement income (expense), net	13,468	12,656	(52,707)	(131,106)	—
Litigation expense	—	—	—	—	(4,401)
Restructuring expenses	—	—	—	(7,176)	—
Reorganization items, net	—	—	140,907	(47,503)	—
Other income (expense), net	392	1,212	(237)	(3,082)	(2,060)
Total other income (expense), net	(120,135)	(269,107)	(234,439)	(244,879)	(125,215)
Income (loss) before income taxes	106,938	85,649	163,846	55,497	(3,211,624)
Income tax (benefit) provision	(1,050)	442	(13,294)	(654)	(4,404)
Net income (loss)	\$ 107,988	\$ 85,207	\$ 177,140	\$ 56,151	\$ (3,207,220)
Earnings (Loss) per Share:					
Basic (1)	\$ 0.55	\$ 0.43	\$ 1.08	\$ 0.70	\$ (40.14)
Fully diluted (1)	\$ 0.55	\$ 0.43	\$ 1.08	\$ 0.70	\$ (40.14)
Statement of Cash Flows Data (2):					
Net cash provided by (used in):					
Operating activities	\$ 302,416	\$ 310,897	\$ 65,268	\$ 311,070	\$ 515,536
Investing activities	\$ (270,152)	\$ (401,710)	\$ (435,311)	\$ (278,900)	\$ (512,757)
Financing activities	\$ (48,128)	\$ 91,849	\$ (16,737)	\$ 368,621	\$ (7,557)
Balance Sheet Data:					
Cash and cash equivalents	\$ 1,664	\$ 17,014	\$ 16,631	\$ 401,478	\$ 4,143
Working capital (deficit)	\$ (58,272)	\$ (52,481)	\$ (81,065)	\$ 383,185	\$ (3,560,683)
Oil and gas properties	\$ 1,552,419	\$ 1,497,727	\$ 1,325,068	\$ 1,010,466	\$ 851,145
Total assets	\$ 1,815,276	\$ 1,733,288	\$ 1,512,982	\$ 1,540,928	\$ 952,039
Total debt, net(3)(4)	\$ 2,150,210	\$ 2,215,481	\$ 2,116,211	\$ —	\$ 3,390,000
Other long-term obligations	\$ 228,282	\$ 211,895	\$ 197,728	\$ 177,088	\$ 165,784
Total shareholders' (deficit) equity	\$ (844,814)	\$ (1,048,622)	\$ (1,154,636)	\$ (2,928,151)	\$ (2,991,937)

- (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, 2014.
- (2) Cash flows from operating activities for the years ended December 31, 2016 and 2015, have been updated to reflect the retrospective application of the Company's adoption of ASU (as defined below) 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, 2019, 2018 and 2017, costs associated with the issuance of our long-term debt, excluding the costs associated with the Revolving Credit Facility are presented as a direct deduction from the carrying value of the related debt liability on the Consolidated Balance Sheet.

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

The following discussion and analysis should be read in conjunction with our consolidated financial statements and related notes thereto included elsewhere in this report. Further, we encourage you to revisit the Forward-Looking Statements section in Item 1A. "Risk Factors."

Going Concern

As a result of our significant indebtedness and extremely challenging current market conditions, we believe we will require a significant restructuring of our balance sheet in order to continue as a going concern in the long term. We have based this belief on assumptions and estimates which are to some degree subjective and may vary considerably from actual results, and we could spend our available financial resources less or more rapidly than currently expected.

The report of the Company's independent registered public accounting firm that accompanies its audited consolidated financial statements in this Annual Report on Form 10-K contains an explanatory paragraph regarding the substantial doubt about the Company's ability to continue as a going concern. The consolidated financial statements do not include any adjustments that might result from the outcome of the going concern uncertainty.

Under our Credit Agreement and Term Loan Agreement, we are required to deliver audited, consolidated financial statements without a going concern or like qualification or explanation. Because the audit report prepared by our auditors with respect to the financial statements in this Form 10-K includes an explanatory paragraph expressing uncertainty as to our ability to continue as a going concern, we will be in default under each of the Credit Agreement and Term Loan Agreement on April 14, 2020 when we deliver our financial statements to the lenders under the Credit Agreement and the Term Loan Agreement, respectively. We expect that we will be precluded from drawing additional amounts under the Credit Agreement while the default exists. There is a 30-day grace period related to this covenant in each of the Credit Agreement and the Term Loan Agreement. If we do not obtain a waiver or other suitable relief from the lenders under the Credit Agreement or the Term Loan Agreement before the expiration of the 30-day grace period, an event of default under each of the Credit Agreement and Term Loan Agreement would occur. If an event of default occurs, the lenders could accelerate the loans outstanding under the Credit Agreement and Term Loan Agreement. In addition, if the lenders under our Credit Agreement and Term Loan Agreement accelerate the loans outstanding thereunder, we will then also be in default under the indentures related to our Second Lien Notes and our Unsecured Notes. If we default under those indentures, the holders of the Second Lien Notes and Unsecured Notes could accelerate those notes. At this time, we do not expect to obtain a waiver of this requirement.

In February and March 2020, we entered into confidentiality agreements and commenced discussions with certain holders of the Company's long-term debt and their legal and financial advisors. Negotiations and discussions with certain debtholders and their advisors are ongoing, although as of the date of this filing no definitive agreements have been reached regarding any amendments, restructuring or other transactions relating to the Company's indebtedness.

There can be no assurance that our efforts will result in any agreement or what the terms of any agreement will be. If an agreement is reached and we pursue a restructuring, it may be necessary for us to file a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code or the Canadian Bankruptcy and Insolvency Act in order to implement an agreement through the confirmation and consummation of a plan of reorganization approved by the bankruptcy court in the bankruptcy proceedings. We also may conclude that it is necessary to initiate proceedings under Chapter 11 of the United States Bankruptcy Code to implement a restructuring of our obligations even if we are unable to reach an agreement with our creditors and other relevant parties regarding the terms of such a restructuring. In either case, such a proceeding could be commenced in the near term. If a plan of reorganization is implemented in a bankruptcy proceeding, it is possible that holders of claims and interests with respect to, or rights to acquire, our equity securities would be entitled to little or no recovery, and those claims and interests may be canceled for little or no consideration. If that were to occur, we anticipate that all or substantially all of the value of all investments in our equity securities would be lost and that our equity holders would lose all or substantially all of their investment. It is also possible that our other stakeholders, including holders of our Second Lien and Unsecured Notes, would be entitled to little or no recovery, and those claims and interests may also be canceled for little or no consideration.

We believe the long-term outlook for our business is favorable despite the continued uncertainty of gas and oil prices and our need for a significant restructuring of our balance sheet. Our resource base, operational expertise, risk management, including an active hedging program, and disciplined investment of capital provide us with an opportunity to generate significant operating cash flow as we maximize the production and efficiency of our long-lived, low cost assets in the Pinedale field. However, the continued prolonged period of depressed commodity prices and our current levels of indebtedness have caused us to conclude that a significant restructuring of our balance sheet is necessary in order to continue as a going concern. We discuss these matters in further detail under, among other places, in Note 1 to our Consolidated Financial Statements.

Operations Overview

Production and Revenues

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

The Company 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 operations through gaining efficiencies with the use of advanced technologies, detailed technical analysis of its properties and leveraging its experience. Inflation has not had, nor is it expected to have in the foreseeable future, a material impact on the Company's results of operations or capital investment program.

The Company currently generates its revenue, earnings and cash flow from the production and sales of natural gas and condensate from its properties in the Pinedale and Jonah fields.

Total production for the year ended December 31, 2019 was 230.1 Bcf of natural gas and 1.7 MBbl of crude oil and condensate, for a total of 240.2 Bcfe of production. The production decrease was driven by reduced drilling activities and decreased capital investment activity during 2019. As noted previously, the Company suspended its operated drilling program in September 2019. The number of Ultra operated vertical wells drilled and turned into sales in 2019 decreased to 71 vertical wells from 94 vertical wells in 2018. For the year ended December 31, 2019, cash flow from operations was \$302.4 million.

Late in the third quarter of 2019, the Company decided to release its remaining drilling rig and suspend its operated drilling program in the Pinedale field. This decision was based on natural gas pricing remaining near multi-year lows and the determination that investment returns at such commodity prices were inadequate to justify the deployment of further capital. This decision reduced the level of total 2019 capital investment. Going into 2020, the Company will continue to evaluate the commodity price environment and the projected investment returns, as it manages its capital investment program. The Fifth Amendment established a maximum capital expenditure level, as defined, of \$65 million, \$10 million, and \$5 million, for the quarters ended September 30, 2019, December 31, 2019, and quarterly thereafter, with the ability to carryforward unused amounts up to \$5 million in aggregate. Per the definition of maximum capital expenditures in the Fifth Amendment, the Company expended \$6.8 million in the quarter ended December 31, 2019, and \$53.7 million in the quarter ended September 30, 2019, resulting in a \$5 million carryover as of December 31, 2019.

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, costless collars and/or deferred premium puts for a portion of its estimated future production. In addition to fixed price swap contracts, the Company utilizes costless collars and deferred put contracts, with low premium costs, to provide a degree of floor price protection and allow the Company to participate in more upward price exposure. The Company also enters into short-term fixed price forward physical delivery contracts for natural gas and oil from time to time. Under the Credit Agreement, the Company was subject to minimum hedging requirements through March 31, 2020, whereby the Company was required to hedge a minimum of 50% of the projected proved developed producing natural gas reserve volumes projected to be produced through such date. Beginning April 1, 2020, the Company was no longer subject to a minimum hedging requirement.

Capital Investments

As previously mentioned, the Company suspended its operated drilling program in the Pinedale field in September 2019. The total capital investment in oil and gas properties was \$241.1 million and resulted in a total of 93 gross (77.6 net) vertical wells and 1 gross (0.9 net) horizontal wells which were drilled and turned into sales in the Pinedale field.

The operated well costs for vertical wells averaged \$3.1 million per well during 2019, with final operated well costs of \$2.9 million per well in the third quarter when the Company ceased its drilling program. The decline of well costs in 2019 is a result of an increased success rate of the two-string drilling design over the year, as well as overall improvements in efficiencies and cost management throughout the year. Included in the well results was the successful completion of seven wells with the two-string design in third quarter 2019 at an average well cost of \$2.65 million per well, highlighting improvement of the selection of the locations for this application in the Pinedale Field, as well as the knowledge gained over the course of the year as to the application of the techniques deployed.

Liquidity and Working Capital

As of December 31, 2019, the Company had \$64.7 million outstanding under its Revolving Credit Facility. As of the date of this filing, the Company's borrowing base is \$1.075 billion, as established by the Sixth Amendment dated February 14, 2020, with lender commitments for the Revolving Credit Facility at \$100 million.

Availability under the Revolving Credit Facility is defined as the undrawn portion of the commitment, plus the unrestricted cash of the Company, and net of any outstanding letters of credit outstanding for a total availability of \$130.3 million as of December 31, 2019.

Based on the Sixth Amendment, the commitment amount under the Revolving Credit Facility was reduced from \$120 million to \$100 million with the associated borrowing base being set at \$1.075 billion effective April 1, 2020. Also included in the Sixth Amendment was the reduction of the excess cash threshold to \$15 million as part of the anti-cash hoarding provisions and established quarterly borrowing base redeterminations. The next borrowing base redetermination will be completed on or before July 1, 2020.

The significant risks and uncertainties described above raise substantial doubt about the Company's ability to continue as a going concern. The report of the Company's independent registered public accounting firm that accompanies its audited consolidated financial statements in this Annual Report on Form 10-K contains an explanatory paragraph regarding the substantial doubt about the Company's ability to continue as a going concern. As a result, the Company has reclassified all of its total outstanding debt as current. The explanatory paragraph regarding the substantial doubt about the Company's ability to continue as a going concern in the audited consolidated financial statements in this Annual Report on Form 10-K also creates a default under each of the Credit Agreement and Term Loan Agreement on April 14, 2020. We expect that we will be precluded from drawing additional amounts under the Credit Agreement while the default exists. If the Company does not obtain a waiver or other suitable relief from the lenders under the Credit Agreement or the Term Loan Agreement before the expiration of the 30-day grace period, an event of default under each of the Credit Agreement and Term Loan Agreement would occur. If an event of default occurs, the lenders could accelerate the loans outstanding under the Credit Agreement and Term Loan Agreement. Accordingly, the Company believes there is substantial doubt that its projected cash flows from operations and liquidity will be adequate to meet its obligations for the ensuing twelve months.

Even if the Company is able to obtain a waiver or other suitable relief from the lenders under the Credit Agreement or the Term Loan Agreement, the possibility remains that future commitments under the Credit Agreement could decrease below the outstanding balance of the Revolving Credit Facility, because of a downward redetermination of the borrowing base and Commitment Amount, and the Company would be required to enter into a mandatory repayment schedule to satisfy the deficiency. Should the lenders not support such a repayment schedule, intramonth liquidity for the Company could be inadequate to meet obligations on a timely basis.

In the event that the borrowing base is reduced to an amount that is less than the outstanding borrowings under the Term Loan Agreement, then commitments under the Revolving Credit Facility would be reduced to zero and Ultra Resources would become subject to additional coverage tests under the Term Loan Agreement. Among these new requirements is an asset coverage test and, if not satisfied, Ultra Resources would be required to make mandatory prepayments to the Term Loan Lenders in order to cure any deficiency. Failure to make such required payments would result in an event of default under the Term Loan Agreement.

The Revolving Credit Facility has \$35.0 million of the commitments available for the issuance of letters of credit. 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 250 to 350 basis points based upon the borrowing base utilization grid. The applicable margin increases by 25 basis points in the event the Company's consolidated net leverage ratio, as defined, exceeds 4.00 to 1.00.

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 Revolving Credit Facility loans mature on January 12, 2022.

As of April 10, 2020, the Company had a cash balance of approximately \$14.7 million, \$43.0 million due under the Revolving Credit Facility, and \$10.2 million of issued and undrawn letters of credit.

Additionally, the Company continues to evaluate liability management and strategic alternatives in order to address its liquidity and balance sheet issues.

As mentioned previously, our significant indebtedness and extremely challenging current market conditions have had a significant adverse impact on our business, and as a result of our financial condition, substantial doubt exists about our ability to continue as a going concern. A failure by us to comply with our financial covenants or to comply with the other restrictions in our financing agreements is expected to result in reduced borrowing capacity or an event of default, causing our debt obligations under such financing agreements (and any other indebtedness or contractual obligations to the extent linked to it by reason of cross-default or cross-acceleration provisions) to potentially become immediately due and payable.

2018/2019 Debt Exchange Transaction

In December 2018, the Company exchanged (i) \$505 million aggregate principal amount, or 72.1%, of the 2022 Notes, and (ii) \$275 million aggregate principal amount, or 55%, of the 2025 Notes (as defined below) of Ultra Resources for (a) \$545.0 million aggregate principal amount of new Second Lien Notes, and (b) an aggregate of 10,919,499 Warrants (such transaction, the “2018 Exchange Transaction”).

Then in 2019, the Company entered into an incremental note exchange transaction that provided for the exchange of \$44.6 million aggregate principal amount of 2022 Notes for \$27.0 million aggregate principal amount of Second Lien Notes (together with the 2018 Exchange Transaction, the “Exchange Transactions”), as allowed by the Indenture, dated December 21, 2018 (the “Second Lien Notes Indenture”).

The Company evaluated the accounting treatment of the Exchange Transactions under ASC 470, *Debt*. The portion of the senior Unsecured Notes (as defined below) which were exchanged for Second Lien Notes was accounted for as a troubled debt restructuring (“TDR”). The amount of extinguished debt is amortized over the remaining life of the Second Lien Notes using the effective interest method and recognized as a reduction to interest expense. As a result, our reported interest expense following the Exchange Transactions will be significantly less than the contractual cash interest payments throughout the term of the Second Lien Notes.

2017 Chapter 11 Plan of Reorganization

On April 29, 2016, 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. The effects of the Plan were included in the Consolidated Financial Statements as of December 31, 2017, and the related adjustments thereto were recorded in our Consolidated Statement of Operations as reorganization items for the twelve months ended December 31, 2017. See Note 16 in the Notes to the Consolidated Financial Statements for further discussion of these matters.

We were not required to apply fresh start accounting to our consolidated 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 post-petition liabilities and allowed claims.

Results of Operations — Year Ended December 31, 2019 vs. Year Ended December 31, 2018

Beginning as of January 1, 2019, the Company revised its estimated administrative costs associated with its operations and classified as Lease operating expenses on the Consolidated Statement of Operations. During 2018 and 2019, the Company has taken steps to drive efficiencies through its operations which resulted its overhead costs being less than the inflation adjusted overhead rates set by the Council of Petroleum Accountants Societies. Accordingly, the Company reduced the amount of costs categorized as Lease operating expenses, with General and administrative expenses absorbing a larger portion of the Company’s total administrative costs.

The following table summarizes our presents selected production and financial information for the periods indicated:

	For the year ended December 31,		
	2019	2018	% change
(Amounts in thousands, except per unit data)			
Production, Commodity Prices and Revenues:			
<i>Production:</i>			
Natural gas (Mcf)	230,121	260,406	-12%
Crude oil and condensate (Bbls)	1,683	2,442	-31%
Total production (Mcf)	240,219	275,058	-13%
<i>Commodity Prices:</i>			
Natural gas (\$/Mcf, incl realized hedges)	\$ 2.50	\$ 2.48	1%
Natural gas (\$/Mcf, excluding hedges)	\$ 2.77	\$ 2.77	0%
Crude oil and condensate (\$/Bbl, incl realized hedges)	\$ 59.97	\$ 59.44	1%
Crude oil and condensate (\$/Bbl, excluding hedges)	\$ 57.78	\$ 62.88	-8%
<i>Revenues:</i>			
Natural gas sales	\$ 637,007	\$ 722,313	-12%
Oil sales	\$ 97,231	\$ 153,534	-37%
Other revenues	\$ 7,794	\$ 16,652	-53%
Total operating revenues	\$ 742,032	\$ 892,499	-17%
<i>Derivatives:</i>			
Realized gain (loss) on commodity derivatives	\$ (58,878)	\$ (85,413)	-31%
Unrealized gain (loss) on commodity derivatives	\$ 54,282	\$ (59,799)	-191%
Total gain (loss) on commodity derivatives	\$ (4,596)	\$ (145,212)	-97%
Operating Costs and Expenses:			
Lease operating expenses	\$ 70,608	\$ 90,290	-22%
Facility lease expense	\$ 25,468	\$ 25,947	-2%
Production taxes	\$ 79,459	\$ 93,322	-15%
Gathering fees	\$ 78,261	\$ 89,294	-12%
Transportation charges	\$ 1,496	\$ 512	192%
Depletion, depreciation and amortization	\$ 204,227	\$ 204,255	0%
General and administrative expenses	\$ 26,551	\$ 25,005	6%
<i>Per Unit Costs and Expenses (\$/Mcf):</i>			
Lease operating expenses	\$ 0.29	\$ 0.33	-12%
Facility lease expense	\$ 0.11	\$ 0.09	22%
Production taxes	\$ 0.33	\$ 0.34	-3%
Gathering fees	\$ 0.33	\$ 0.33	0%
Transportation charges	\$ 0.01	\$ —	0%
Depletion, depreciation and amortization	\$ 0.85	\$ 0.74	15%
General and administrative expenses	\$ 0.11	\$ 0.09	22%

Production, Commodity Prices and Revenues:

Production. During the year ended December 31, 2019, production decreased on a gas equivalent basis to 240.2 Bcfe from 275.1 Bcfe for the same period in 2018. The decrease is primarily attributable to a decrease in capital investment which occurred in 2019 and resulted in lower production for the period. Given the Company's decision to suspend its operated drilling program, as announced in September 2019, it is expected that production will decrease in future periods based on the natural decline of the proven producing developed wells that were online as of December 31, 2019. Additionally, the divestiture of the assets in Utah during late September 2018 resulted in a decrease in production by approximately 3.2 Bcfe in 2019 compared to 2018.

Revenues. During the year ended December 31, 2019, revenues decreased to \$742.0 million for the year ended December 31, 2019, as compared to \$892.5 million in 2018. This decrease primarily attributable to the decrease in total production.

Commodity prices — natural gas. Realized natural gas prices, including realized gains and losses on commodity derivatives, increased to \$2.50 per Mcf during the year ended December 31, 2019 as compared to \$2.48 per Mcf during 2018. This net realized price is a combination of the natural gas prices at Henry Hub and our basis differentials at NwRox. The Company has open natural gas price commodity derivative contracts as of December 31, 2019. See Note 8 for additional details relating to these derivative contracts. During the year ended December 31, 2019 and 2018, the Company's average price for natural gas, excluding realized gains and losses on commodity derivatives, was flat at \$2.77 per Mcf. Trades indicate that the basis differentials for the forward-looking basis market for 2020 and 2021 are negative to Henry Hub by approximately \$0.23 and \$0.36, respectively, highlighting potential volatility that can occur in our natural gas pricing. The actual results for January and February 2020 were \$1.00 and \$0.07, respectively.

Commodity prices — oil. Realized oil prices, including realized gains and losses on commodity derivatives, increased to \$59.97 per barrel during the year ended December 31, 2019, as compared to \$59.44 per barrel during 2018. The Company has open oil price commodity derivative contracts as of December 31, 2019. See Note 8 for additional details relating to these derivative contracts. During the year ended December 31, 2019, the Company's average price for oil, excluding realized gains and losses on commodity derivatives, was \$57.78 per barrel compared to \$62.88 per barrel for the same period in 2018.

Operating Costs and Expenses:

The Company has continued its historical focus on effective cost management. Historically, the operating costs decreased on a per unit basis in 2019 as compared to 2018 primarily due to the sale of the Utah assets in September 2018. Prospectively and on a unit basis, the Company expects pressure on Lease operating expense ("LOE") and General and administrative expenses due to the expected decrease in future production as the Company has suspended its operated drilling program. Management expects it can mitigate some of this per unit pressure through further cost management and investment initiatives. However, with production decreasing, well counts increasing, certain costs being fixed, and capital deployment being limited, the cost saving activities are not expected to fully mitigate the pressure on per unit costs.

Lease Operating Expense. LOE decreased to \$70.6 million for the year ended December 31, 2019, compared to \$90.3 million during the same period in 2018. The decrease for the period was primarily driven by the change to the estimate used to determine the overhead rate used for the Company's administrative expenses, as previously discussed. The decrease in the overhead charged to the LOE was approximately \$14.7 million, compared to the same period in 2018. Additionally, the decrease in LOE was driven by the sale of the Utah assets in September 2018. The Utah production and related LOE approximated \$8.6 million of expense, or \$0.03 per Mcfe, for the year ended December 31, 2018. On a unit of production basis, consolidated LOE costs were \$0.29 per Mcfe for 2019 and \$0.33 per Mcfe for 2018.

General and Administrative Expenses. General and administrative expenses slightly increased to \$26.6 million for the year ended December 31, 2019 compared to \$25.0 million for the same period in 2018. The increase in general and administrative expenses is primarily attributable to the revision in the estimate of administrative costs attributed to LOE, as previously described. The change was partially offset by a \$9.2 million decrease in share-based compensation expense recognized during 2019. On a per unit basis, general and administrative expenses increased to \$0.11 per Mcfe at December 31, 2019 from \$0.09 per Mcfe at December 31, 2018.

The Company analyzes the combined LOE and General and administrative expenses as controllable costs. The combined LOE and General and administrative expenses for the year ended December 31, 2019, decreased to \$0.40 per Mcfe compared to \$0.42 per Mcfe for the same period in 2018. Management also analyzes the combined LOE and General and administrative expenses, excluding the non-cash element of stock compensation. The cash component of LOE and General and administrative expenses for the years ended December 31, 2019 and 2018, was \$0.39 per Mcfe and \$0.38 per Mcfe, respectively.

Facility Lease Expense. In 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 LGS (the "Lease Agreement"). The Lease Agreement provides for an initial term of 15 years and annual base rent of \$20.0 million during the initial term (as adjusted annually for changes based on the consumer price index). The base rent may increase if certain volume thresholds are exceeded. For the year ended December 31, 2019, the Company recognized operating lease expense associated with the Lease Agreement of \$25.5 million, or \$0.11 per Mcfe compared with \$25.9 million, or \$0.09 per Mcfe in 2018.

Production Taxes. During the year ended December 31, 2019, production taxes decreased to \$79.5 million compared to \$93.3 million during the same period in 2018, or \$0.33 per Mcfe in 2019, compared to \$0.34 per Mcfe in 2018. Production taxes are primarily calculated based on a percentage of revenue from the physical production and realized revenues, excluding derivative hedge settlements, after certain deductions and were 10.7% of revenues for the year ended 2019 and 10.5% for the same period in 2018.

Gathering Fees. Gathering fees decreased to \$78.3 million for the year ended December 31, 2019, compared to \$89.3 million during the same period in 2018, related to decreased production volumes. On a per unit basis, gathering fees remained flat at \$0.33 per Mcfe for the years ended December 31, 2018 and 2019. Because the gathering fees are charged on a per unit basis, management expects the gathering fees on a unit basis to be relatively consistent into the future, except for contractual pricing adjustments for such services.

Transportation Charges. Transportation charges increased to \$1.5 million for the year ended December 31, 2019, compared to \$0.5 million during the same period in 2018. Commencing on December 1, 2019 and extending for a term expiring December 31, 2026, the Company has committed to firm transportation capacity of 200,000 Dekatherms per day at a rate of approximately \$0.37 per Dekatherm on the Rockies Express Pipeline. This agreement provides 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.

Depletion, Depreciation and Amortization. On a unit of production basis, Depletion, depreciation, and amortization (“DD&A”) increased to \$0.85 per Mcfe at December 31, 2019 from \$0.74 per Mcfe at December 31, 2018, primarily related to decreased natural gas pricing and decreased reserves as a result of not including PUD reserves in total proved reserve estimates at December 31, 2019. Given the lower production in 2019 and the higher DD&A rate previously described, the total DD&A expenses remained flat at \$204.2 million for the years ended December 31, 2019 and 2018.

Other Operating Expenses, net. During the year ended December 31, 2019, the Company incurred \$28.9 million of other operating expenses, of which \$14.0 million was attributable to settlement agreements; \$7.5 million was attributable to inventory write-downs; \$1.8 million of expenses related to rig contract terminations; \$3.3 million is attributable to the provision for uncollectible accounts; and \$2.3 million of other recurring and nonrecurring expenses. During the year ended December 31, 2018, the Company recognized \$9.1 million of other expenses, of which \$4.9 million is attributable to the provision for uncollectible accounts and \$4.2 million is attributable to the Houston office relocation.

Other Income and Expenses:

Interest Expense. Interest expense decreased to \$129.4 million during the year ended December 31, 2019, compared to \$148.3 million during the same period in 2018. Interest expense is comprised of four primary elements: (i) cash interest expense; (ii) PIK interest expense; (iii) amortization of deferred premium; and (iv) amortization of deferred financing costs. The table below reflects the comparative amounts for each element in each period presented. The cash interest expense increased for the year ended December 31, 2019 as compared to the same period in 2018 due to the higher interest rate Second Lien Notes that were issued in December 2018.

	For the year ended December 31,	
	2019	2018
	(In thousands)	
Cash interest expense	\$ 145,339	\$ 137,812
PIK interest expense	12,867	377
Amortization of deferred premium	(41,774)	(1,083)
Amortization of deferred financing costs and discount	12,966	11,210
Total interest expense	\$ 129,398	\$ 148,316

Contract Settlement Income (Expense), Net. The Company recognized \$13.5 million of net contract settlement income for the year ended December 31, 2019, compared to \$12.7 million of contract settlement income for the year ended December 31, 2018. In 2019 and 2018, the Company entered into settlement agreements (collectively, the “Settlement Agreements”) with holders of certain claims related to Ultra Resources’ prepetition indebtedness (the “Claimants”) pursuant to which the parties agreed to settle the pending disputes between the Claimants and the Company. As of December 31, 2019, there are approximately \$240 million of claims outstanding by the Company, as plaintiffs, under the make-whole litigation.

Deferred Gain on Sale of Liquids Gathering System. During the year ended December 31, 2018, the Company recognized \$10.6 million in Deferred gain on sale of the liquids gathering system relating to the sale of the Pinedale LGS in 2012. On January 1, 2019, the Company recognized the remaining deferred gain as an opening balance sheet adjustment to Retained loss upon adoption of ASU 2016-02, *Leases (Topic 842)*. See Note 12 for additional information.

Commodity Derivatives:

Gain (Loss) on Commodity Derivatives. During the year ended December 31, 2019, the Company recognized a loss of \$4.6 million related to commodity derivatives. For the contracts settled during 2019, the Company recognized \$58.9 million related to realized loss. 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 \$54.3 million unrealized gain on remaining commodity derivative contracts as of December 31, 2019. The unrealized gain or loss on commodity derivatives represents the non-cash item attributable to the change in the fair value of these derivative instruments.

During the year ended December 31, 2018, the Company recognized a loss of \$145.2 million related to commodity derivatives. Of this total, the Company recognized \$85.4 million related to realized loss and \$59.8 million related to unrealized loss during the year ended December 31, 2018.

Income from Operations:

Pretax Income. The Company recognized income before income taxes of \$106.9 million for the year ended December 31, 2019, compared with income of \$85.6 million for the same period in 2018. The increase in earnings is primarily attributable to a decrease in operating expenses and interest expense. Additionally, there was a decrease in the loss recognized on the commodity derivatives as of December 31, 2019 compared the same period of 2018.

Income Taxes. The Company recorded a \$1.1 million tax benefit for the year ended December 31, 2019, as a result of IRS refunds for previously sequestered amounts related to AMT refunds. The Company has recorded a valuation allowance against all of its net deferred tax asset balance as of December 31, 2019. Some or all of this valuation allowance may be reversed in future periods against future income if any of its deferred tax assets become recognizable.

Net Income. For the year ended December 31, 2019, the Company recognized net income of \$108.0 million or \$0.55 per diluted share, as compared with net income of \$85.2 million or \$0.43 per diluted share for the same period in 2018. The operating income and operating expense elements together with the decreased interest expense were the primary elements for the increase in earnings in 2019 as compared to 2018.

Results of Operations — Year Ended December 31, 2018 vs. Year Ended December 31, 2017

A comparative discussion of our results of operations and other operating data for the years ended December 31, 2018 and December 31, 2017 is set out in our Annual Report on Form 10-K for the year ended December 31, 2018, under the heading "Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations - Year ended December 31, 2018 vs. December 31, 2017" is available free of charge on the SEC's website, www.sec.gov, and is incorporated by reference herein.

LIQUIDITY AND CAPITAL RESOURCES

Overview. During the year ended December 31, 2019, we funded our operations primarily through cash flows from operating activities and borrowings under the Revolving Credit Facility. In addition to cash flows from operations, the Revolving Credit Facility is our primary source of liquidity. At December 31, 2019, the Company's cash position was \$1.7 million, with \$64.7 million of outstanding borrowings under the Revolving Credit Facility. The Revolving Credit Facility balance decreased by \$39.3 million from December 31, 2018. The Company was able to make repayments under the Revolving Credit Facility due to its decision to curtail the deployment of capital and to deliver on its strategy of generating operating cash flows in excess of capital deployment. In addition to the borrowings outstanding under the Revolving Credit Facility, the Company had \$1.9 billion of other indebtedness outstanding in the form of term loans, secured notes and unsecured notes with maturities commencing in 2022.

At December 31, 2019, the Company had a commitment of \$200.0 million under its Revolving Credit Facility and a borrowing base of \$1.175 billion, of which \$64.7 million was outstanding. Availability under the Revolving Credit Facility is the undrawn portion of the commitment, net of any outstanding letters of credit outstanding, plus the unrestricted cash of the Company.

Based on the Sixth Amendment, the commitment amount under the Revolving Credit Facility was reduced from \$120 million to \$100 million, with the associated borrowing base being set at \$1.075 billion, effective April 1, 2020. The Sixth Amendment also reduced the excess cash threshold to \$15 million as part of the anti-cash hoarding provisions and established a quarterly, rather than semi-annual, redetermination of the borrowing base. The next borrowing base redetermination is scheduled to be completed on July 1, 2020.

Given the potential for decreases in future commodity prices, the borrowing base level is subject to redetermination risk. If the borrowing base or the commitment amount were redetermined below the levels of outstanding indebtedness associated with the Revolving Credit Facility and Term Loan, or if the commitment amount was inadequate to fund ongoing operations, the Company could potentially trigger mandatory repayment provisions of the Revolving Credit Facility or demands to reduce the Term Loan balance.

Because the audit report prepared by the Company's independent registered public accounting firm includes an explanatory paragraph expressing uncertainty as to the Company's ability to continue as a going concern, the Company is in default under each of the Credit Agreement and Term Loan Agreement on April 14, 2020 when it delivers its financial statements to the lenders under the Credit Agreement. There is a 30-day grace period related to this covenant in the Credit Agreement. If the Company does not obtain a waiver or other suitable relief from the lenders under the Credit Agreement or the Term Loan Agreement before the expiration of the 30-day grace period, an event of default under each of the Credit Agreement and Term Loan Agreement would occur. As a result of the going concern qualification in the independent registered public accounting firm's report to the December 31, 2019 financial statements, the Company's immediate liquidity is limited to cash as it will not have access to its Revolving Credit Facility beginning on April 15, 2020.

Capital Expenditures. For the year ended December 31, 2019, total capital expenditures were \$241.1 million. During this period, the Company participated in 93 gross (77.6 net) vertical wells and 1 gross (0.9 net) horizontal wells in Wyoming that were drilled to total depth and turned into sales.

2020 Capital Investment Plan. For 2020, our capital expenditures have been significantly reduced and we plan for only minimal capital investments in our Pinedale field between \$10 and \$20 million. The Company is also restricted to investing no more than \$5 million in capital, as defined by the Credit Agreement, per quarter (plus a cumulative \$5 million of additional carry-over amount), thereby limiting the amount of capital available for development. We expect to fund these capital expenditures through cash flows from operations, borrowings under the Revolving Credit Facility, and cash on hand.

Credit Agreement. Ultra Resources entered into a Credit Agreement as the borrower with the Company and UP Energy Corporation, as parent guarantors, with Bank of Montreal, as administrative agent (the "RBL Administrative Agent"), and with the other lenders party thereto from time to time (collectively, the "RBL Lenders"), providing for a revolving credit facility (the "Revolving Credit Facility") subject to a borrowing base redetermination, which limits the aggregate amount of first lien debt under the Revolving Credit Facility and Term Loan Agreement.

As previously mentioned, on February 14, 2020, Ultra Resources entered into the Sixth Amendment with the RBL Administrative Agent and the RBL Lenders party thereto. Pursuant to the Sixth Amendment and the spring 2020 redetermination, the Borrowing Base (as defined in the Credit Agreement) was reduced, effective April 1, 2020 to \$1.075 billion, with \$100 million attributed to the Revolving Credit Facility. As described in previous periodic reports, the commitment amount for the Revolving Credit Facility was reduced from \$120 million to \$100 million, as established by the Sixth Amendment. The Sixth Amendment also reduced the excess cash threshold to \$15 million as part of the anti-cash hoarding provisions and established a quarterly, rather than semi-annual, redetermination of the borrowing base. The next borrowing base redetermination is scheduled to be completed on or before July 1, 2020.

Other significant provisions of the Credit Agreement, including the recent amendments, are described below:

- elimination of all financial maintenance covenants;
- required minimum hedging on projected natural gas volumes for at least 50% through March 31, 2020, and no minimum hedging requirements exist thereafter;
- limitation of capital expenditures of \$65 million, \$10 million and \$5 million, for the quarters ended September 30, 2019, December 31, 2019, and quarterly thereafter, with the ability to carryforward unused amounts up to \$5 million in aggregate; and
- ability to repurchase indebtedness, including borrowings under the Company's Senior Secured Term Loan, Senior Secured Second Lien Notes, 6.875% Senior Notes due 2022 and 7.125% Senior Notes due 2025 under certain circumstances, including having no amounts drawn on the Revolving Credit Facility, the Company having established adequate cash reserves, satisfaction of a first lien incurrence test, each as set forth in the Fifth Amendment, and compliance with the Company's other debt documents. The Term Loan and the Second Lien Notes continue to have prohibitions against the use of cash to repurchase debt. Therefore, in order for the Company to utilize this provision provided by the Credit Agreement, the Company would have to receive additional approval from both the Term Loan Lenders and the holders Second Lien Notes.

The Revolving Credit Facility has \$35.0 million of the commitments available for the issuance of letters of credit. 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 based upon the borrowing base utilization grid. The applicable margin increases by 25 basis points in the event the Company's consolidated net leverage ratio, as defined, exceeds 4.00 to 1.00.

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 Revolving Credit Facility loans mature on January 12, 2022.

As noted above, the Fifth Amendment established a maximum capital expenditure level. Per the definition of maximum capital expenditures in the Fifth Amendment, the Company expended \$6.8 million in the quarter ended December 31, 2019, and \$53.7 million in the quarter ended September 30, 2019, resulting in a \$5 million carryover as of December 31, 2019.

The Revolving Credit Facility also contains customary affirmative and negative covenants including 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. As of December 31, 2019, Ultra Resources was in compliance with its debt covenants under the Revolving Credit Facility. Subsequent to December 31, 2019, the audit report the Company received with respect to its consolidated financial statements contains an explanatory paragraph expressing uncertainty as to the Company's ability to continue as a going concern, the delivery of which constitutes a default under the Credit Agreement.

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

Term Loan. Ultra Resources, entered into a Term Loan Agreement (the "Term Loan Agreement") as the borrower with the Company and UP Energy Corporation, as parent guarantors, with Barclays Bank PLC ("Barclays"), as administrative agent (the "Term Loan Administrative Agent"), and with the other lenders party thereto from time to time (collectively, the "Term Loan Lenders"), providing for a term loan credit facility. As of December 31, 2019, Ultra Resources had a balance of approximately \$968.8 million in borrowings, including \$1.1 million of PIK interest.

In December 2018, Ultra Resources and the parent guarantors entered into the First Amendment to the Term Loan Agreement (the "Term Loan Amendment") with the Term Loan Administrative Agent and the Term Loan Lenders party thereto. Pursuant to the Term Loan Amendment, the parties agreed, among other things, to amend the Term Loan Agreement to permit the issuance of the Second Lien Notes and the 2018 Exchange Transaction, to increase the interest rate payable by 100 basis points, such increase comprising 75 basis points payable in cash and 25 basis points payable in kind, and to revise certain covenants and other provisions of the Term Loan Agreement, including, but not limited to:

- introducing call protection, with the remaining term of the call protection at 101% until December 21, 2020;
- restrictions on the Revolving Credit Facility; including amendments and refinancing of the Revolving Credit Facility as more thoroughly described in the Term Loan Amendment;
- deleting the ability to increase commitments under the Term Loan;
- collateral coverage established at 95% of total PV-9 of Proven Reserves (as defined in the Term Loan Agreement);
- removing the ability to create, invest in and utilize unrestricted subsidiaries;
- prohibiting the repurchase of more than \$50 million of the 2022 Notes or the 2025 Notes at their respective maturity dates or within one year thereof;
- further limiting the Company's ability to incur unsecured debt, repay junior debt, and make restricted payments and investments as more thoroughly described in the Term Loan Amendment; and
- providing the ability for the Company to exchange unsecured borrowings to third lien debt within a construct as described in the Term Loan Amendment.

Borrowings under the Term Loan Agreement bear interest at a rate equal to either (a) a customary London interbank offered rate plus 400 basis points or (b) the base rate plus 300 basis points, in each case, of which 25 basis points of the applicable margin is payable in-kind ("PIK") solely upon election by Ultra Resources. During 2019, the Company elected the PIK option for several of its selected interest payments. In the third quarter 2019, the Company began electing not to utilize this PIK option. Beginning in June 2019, the borrowings under the Term Loan Agreement amortize in equal quarterly installments in aggregate annual amounts equal to 0.25% of the initial aggregate principal amount. Remaining borrowings under the Term Loan Agreement mature on April 12, 2024.

Borrowings under the Term Loan Agreement are 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 conditions including a situation in which the Revolving Credit Facility no longer exist, there is a prepayment requirement if the asset coverage ratio is less than 2.0 to 1.0. To the extent any mandatory prepayments equal to six monthly payments are required in order to attain compliance, with such amounts being applied to prepay the borrowings under the Term Loan Agreement.

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, 2019, Ultra Resources was in compliance with all of its debt covenants under the Term Loan Agreement. Subsequent to December 31, 2019, the audit report the Company received with respect to its consolidated financial statements contains an explanatory paragraph expressing uncertainty as to the Company's ability to continue as a going concern, the delivery of which constitutes a default under the Term Loan Agreement.

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.

Second Lien Notes. As of December 31, 2019, Ultra Resources had approximately \$583.9 million, including \$11.8 million of PIK interest, in outstanding borrowings of Senior Secured Second Lien Notes (the "Second Lien Notes") pursuant to the Second Lien Notes Indenture, with Ultra Resources, as issuer, the Company and its other subsidiaries, as guarantors, and Wilmington Trust, National Association, as trustee and collateral agent.

Interest on the Second Lien Notes accrues at (i) an annual rate of 9.00% payable in cash and (ii) an annual rate of 2.00% PIK. The cash interest payment dates for the Second Lien Notes are January 15 and July 15 of each year, commencing in July 2019. The Company has accounted for such PIK interest as an increase to the principal outstanding. The Second Lien Notes will mature on July 12, 2024.

The Second Lien Notes are senior secured obligations of Ultra Resources and rank senior in right of payment to all of its existing and future unsecured senior debt, to the extent of the value of the collateral pledged under the Second Lien Notes Indenture and related collateral arrangements, senior in right of payment to all of its future subordinated debt, and junior in right of payment to all of its existing and future secured debt of senior priority, to the extent of the value of the collateral pledged thereby. The Second Lien Notes are secured by second priority security interests in substantially all assets of the Company. Payment by Ultra Resources of all amounts due on or in respect of the Second Lien Notes and the performance of Ultra Resources under the Indenture are initially guaranteed by the Company.

Prior to December 21, 2021, 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 Second Lien Notes in an amount no greater than the net cash proceeds of certain equity offerings at a redemption price of 111.000% of the principal amount of the Second Lien Notes, plus accrued and unpaid interest (including PIK interest), if any, to the date of redemption, if at least 65% of the original principal amount of the Second Lien Notes remains outstanding and the redemption occurs within 180 days of the closing of such equity offering. In addition, on or after December 21, 2021, Ultra Resources may redeem all or a part of the Second Lien Notes at redemption prices (expressed as percentages of principal amount) equal to 105.500% for the twelve-month period beginning on December 21, 2021, 102.750% for the twelve-month period beginning December 21, 2022, and 100.000% for the twelve-month period beginning December 21, 2023 and at any time thereafter, plus accrued and unpaid interest (including PIK interest), if any, to the applicable redemption date on the Second Lien Notes.

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

The Second Lien Notes 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 or redeem indebtedness; (iii) create or incur certain liens; (iv) enter into affiliate agreements; (v) pay cash dividends, (vi) change the nature of its business or operations, (vii) make certain types of investments, (viii) enter into agreements that restrict distributions from certain restricted subsidiaries and the consummation of mergers and consolidations; (ix) consolidate, merge or transfer all or substantially all of the assets of the Company or any Restricted Subsidiary (as defined in the Second Lien Notes Indenture); and (x) create unrestricted and foreign subsidiaries. The covenants in the Second Lien Notes Indenture are subject to important exceptions and qualifications. Subject to conditions, the Second Lien Notes Indenture provides that the Company and its subsidiaries will no longer be subject to certain covenants when the Second Lien Notes receive investment grade ratings from any two of S&P Global Ratings, Moody's Investors Service, Inc., and Fitch Ratings, Inc.

The Second Lien Notes Indenture contains customary events of default. Unless otherwise noted in the Second Lien Notes Indenture, upon a continuing event of default, 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 Second Lien 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 Second Lien Notes Indenture) or group of Restricted Subsidiaries (as defined in the Second Lien Notes Indenture), that taken together would constitute a Significant Subsidiary, will automatically cause the Second Lien Notes to become due and payable.

Senior Unsecured Notes. At December 31, 2019, Ultra Resources had approximately \$150.4 million of 2022 Notes and \$225.0 million of the 7.125% Senior Notes due 2025 (the "2025 Notes", and together with the 2022 Notes, the "Unsecured Notes") outstanding. The Unsecured Notes are treated as a single class of securities under the Unsecured Notes Indenture.

As previously mentioned, in December 2018, the Company exchanged (i) \$505 million aggregate principal amount, or 72.1%, of the 2022 Notes, and (ii) \$275 million aggregate principal amount, or 55%, of the 2025 Notes of Ultra Resources for (a) \$545.0 million aggregate principal amount of new Second Lien Notes, and (b) an aggregate of 10,919,499 Warrants.

Then in the first quarter of 2019, the Company entered into an incremental note exchange transaction that provided for the exchange of \$44.6 million aggregate principal amount of 2022 Notes for \$27.0 million aggregate principal amount of Second Lien Notes, as allowed by the Second Lien Notes Indenture.

The Company evaluated the accounting treatment of the Exchange Transactions under ASC 470, *Debt*. The portion of the senior Unsecured Notes which were exchanged for Second Lien Notes was accounted for as a TDR. The amount of extinguished debt is amortized over the remaining life of the Second Lien Notes using the effective interest method and recognized as a reduction to interest expense. As a result, our reported interest expense following the Exchange Transactions will be significantly less than the contractual cash interest payments throughout the term of the Second Lien Notes.

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 Unsecured Notes from the issue date until maturity.

The Unsecured Notes Indenture contains customary events of default. Unless otherwise noted in the Unsecured Notes Indenture, upon a continuing event of default, the Trustee, by notice to the Company, or the holders of at least 25% in principal amount of the then outstanding Unsecured Notes, by notice to the Company and the Trustee, may, declare the Unsecured 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 Unsecured Notes Indenture) or group of Restricted Subsidiaries (as defined in the Unsecured Notes Indenture), that taken together would constitute a Significant Subsidiary, will automatically cause the Unsecured Notes to become due and payable.

Cash flows provided by (used in):

Operating Activities. During the year ended December 31, 2019, net cash provided by operating activities was \$302.4 million, a 3% decrease from net cash provided by operating activities of \$310.9 million for the same period in 2018. The decrease in net cash provided by operating activities is attributable to decreased revenues as a result of decreased production. Net cash provided by operating activities is also affected by working capital changes and the timing of cash receipts and disbursements.

Investing Activities. During the year ended December 31, 2019, net cash used in investing activities was \$270.2 million as compared to \$401.7 million for the same period in 2018. The decrease in net cash used in investing activities is largely related to decreased capital investments associated with the Company's drilling activities. In 2018, the Company was drilling vertical and horizontal wells which resulted in higher capital costs. During the first nine months of 2019, the Company was primarily focused on drilling vertical wells. In the third quarter of 2019, the Company announced its decision to suspend its operated drilling program in the Pinedale field while natural gas pricing remains near multi-year lows.

Financing Activities. During the year ended December 31, 2019, net cash used in financing activities was \$48.1 million as compared to net cash provided by financing activities of \$91.8 million for the same period in 2018. The change in net cash used in financing activities is attributable to the payments on the Revolving Credit Facility from operating cash flows in excess of borrowings during 2019.

Outlook

Under our Credit Agreement and Term Loan Agreement, we are required to deliver audited, consolidated financial statements without a going concern or like qualification or explanation. Because the audit report prepared by our auditors with respect to the financial statements in this Form 10-K includes an explanatory paragraph expressing uncertainty as our ability to continue as a "going concern," we will be in default under each of the Credit Agreement and Term Loan Agreement on April 14, 2020 when we deliver our financial statements to the lenders under the Credit Agreement. We expect that we will be precluded from drawing additional amounts under the Credit Agreement while the default exists. There is a 30-day grace period related to this covenant in the Credit Agreement. As previously discussed, at this time, we do not expect to obtain a waiver of this requirement. Without such waiver, an event of default under each of the Credit Agreement and Term Loan Agreement would occur and the lenders could accelerate the loans outstanding under the Credit Agreement and Term Loan Agreement. Please read Item 7 —Management's Discussion and Analysis of Financial Condition and Going Concern for further discussion.

The Company, together with its legal and financial advisors, are undertaking negotiations and discussions with certain debtholders and their advisors, although as of the date of this filing no definitive agreements have been reached regarding any amendments, restructurings or other transactions relating to the Company's indebtedness. If an agreement is reached and we pursue a restructuring, it may be necessary for us to file a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code or the Canadian Bankruptcy and Insolvency Act in order to implement the agreement through the confirmation and consummation of a plan of reorganization approved by the bankruptcy court in the bankruptcy proceedings. We also may conclude that it is necessary to initiate proceedings under Chapter 11 of the United States

Bankruptcy Code to implement a restructuring of our obligations even if we are unable to reach an agreement with our creditors and other relevant parties regarding the terms of such a restructuring. In either case, such a proceeding could be commenced in the near term.

Derivative Financial Instruments

Objectives and Strategy: The Company is exposed to commodity price risk. Refer to Note 8 for quantitative and qualitative information about the financial instruments to which we were a party at December 31, 2019, and from which we may incur future gains or losses from changes in commodity prices. We do not enter into derivative or other financial instruments for speculative or trading purposes.

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, deferred premium puts 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 otherwise receive from increases in commodity prices above the fixed hedge prices.

Under the Credit Agreement, the Company was subject to minimum hedging requirements through March 31, 2020, as described in Note 6. Beginning April 1, 2020, the Company was no longer be subject to a minimum hedging requirement. Refer to Note 8 for the Company's open commodity derivative contracts as of December 31, 2019.

Subsequent to December 31, 2019 and through April 10, 2020, the Company entered into the following open commodity derivative contracts to manage commodity price risk:

Type	Index	Total Volumes	Weighted Average Price Per Unit
		(Bbl)	(\$/Bbl)
Oil swaps			
2020	NYMEX WTI	27,300	\$ 60.55

Additionally, the Company terminated approximately \$1.3 million of commodity derivative contracts subsequent to December 31, 2019 and through April 10, 2020.

Off-Balance Sheet Arrangements

The Company did not have any off-balance sheet arrangements as of December 31, 2019.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2019:

	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	\$ 1,992,748	\$ 1,992,748	\$ —	\$ —	\$ —
Interest payments ⁽¹⁾	32,055	32,055	—	—	—
Transportation contract (REX)	187,691	26,813	53,626	53,626	53,626
Liquids gathering system lease	177,096	22,137	44,274	44,274	66,411
Office space lease	2,652	1,083	1,569	—	—
Total contractual obligations	<u>\$ 2,392,242</u>	<u>\$ 2,074,836</u>	<u>\$ 99,469</u>	<u>\$ 97,900</u>	<u>\$ 120,037</u>

- (1) Interest payments includes projected interest payments based on the variable interest rates which were calculated assuming a 3-month London interbank offered rate plus the applicable basis points as of December 31, 2019. Interest payments have been calculated through March 31, 2020 based on the timing of this filing. Because the total outstanding debt is classified as short-term, the interest expense has not been calculated on a prospective basis.

Outstanding debt and interest payments: The Company has debt financing agreements consisting of the Term Loan Facility, the Second Lien Notes, the Unsecured Notes, and the Revolving Credit Facility. See Note 6 for additional details. The Company included the principal and interest obligations above based on the respective agreements.

Challenging current market conditions have had a significant adverse impact on our business, and, as a result of our financial condition, substantial doubt exists about our ability to continue as a going concern. As a result, we have reclassified our total outstanding debt as short-term. The table above reflects the interest expense through March 31, 2020 based on the timing of this filing. Because the total outstanding debt

is classified as short-term and there is significant uncertainty as to the Company's future ability to operate as a going concern, the interest expense has not been calculated beyond this period for purposes of this disclosure.

Our ability to continue as a going concern depends on many factors, including, among other things, our ability to comply with the covenants in our existing debt agreements and amend or replace our debt agreements as they mature. Please read Item 7 — Management's Discussion and Analysis of Financial Condition and Results of Operations for further discussion. Also, for additional discussion of factors that may affect our ability to continue as a going concern and the potential consequences of our failure to do so, please see Item 1A — Risk Factors.

A failure by us to comply with our financial covenants or to comply with the other restrictions in our financing agreements is expected to result in reduced borrowing capacity or an event of a default, causing our debt obligations under such financing agreements (and any other indebtedness or contractual obligations to the extent linked to it by reason of cross-default or cross-acceleration provisions) to potentially become immediately due and payable.

We cannot provide any assurances that we will be able to comply with the covenants or to make satisfactory alternative arrangements in the event we cannot comply. If satisfactory alternative arrangements are made, the total future interest expense associated with our total outstanding debt is approximately \$650.4 million at December 31, 2019 (\$138.1 million in 2020; \$264.5 million in total for 2021 and 2022; \$243.2 million in total for 2023 and 2024; and \$4.7 million due beyond five years) .

Transportation contract. During our Chapter 11 proceedings in 2016, 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 has committed to 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 agreement provides 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. The Company has demonstrated its ability to mitigate this cost with capacity releases through March 31, 2020, and will continue to seek alternatives to reduce exposure to this commitment and potentially enhance the realized value of the natural gas for which it markets.

Liquids Gathering System lease. In 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 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 when certain volume thresholds are exceeded.

Office space lease. The Company maintains office space in Colorado and Wyoming with total remaining commitments for office leases of \$2.7 million at December 31, 2019.

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 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.

Going Concern. As a result of our significant indebtedness and extremely challenging current market conditions that have had an adverse impact on our business, and as a result of our financial condition, substantial doubt exists about our ability to continue as a going concern. A failure by us to comply with our financial covenants or to comply with the other restrictions in our financing agreements is expected to result in reduced borrowing capacity or an event of default, causing our debt obligations under such financing agreements (and any other indebtedness or contractual obligations to the extent linked to it by reason of cross-default or cross-acceleration provisions) to potentially become immediately due and payable. Accordingly, all debt balances as of December 31, 2019 have been classified as current on the consolidated balance sheet.

In February and March 2020, we entered into confidentiality agreements and commenced discussions with certain holders of the Company's long-term debt and their legal and financial advisors. Negotiations and discussions with certain debtholders and their advisors are ongoing, although as of the date of this filing no definitive agreements have been reached regarding any amendments, restructurings or other transactions relating to the Company's indebtedness.

There can be no assurance that our efforts will result in any agreement or what the terms of any agreement will be. If an agreement is reached and we pursue a restructuring, it may be necessary for us to file a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code or the Canadian Bankruptcy and Insolvency Act in order to implement an agreement through the confirmation and consummation of a plan of reorganization approved by the bankruptcy court in the bankruptcy proceedings. We also may conclude that it is necessary to initiate proceedings under Chapter 11 of the United States Bankruptcy Code to implement a restructuring of our obligations even

if we are unable to reach an agreement with our creditors and other relevant parties regarding the terms of such a restructuring. In either case, such a proceeding could be commenced in the near term. If a plan of reorganization is implemented in a bankruptcy proceeding, it is possible that holders of claims and interests with respect to, or rights to acquire, our equity securities would be entitled to little or no recovery, and those claims and interests may be canceled for little or no consideration. If that were to occur, we anticipate that all or substantially all of the value of all investments in our equity securities would be lost and that our equity holders would lose all or substantially all of their investment. It is also possible that our other stakeholders, including holders of our Second Lien and Unsecured Notes, would be entitled to little or no recovery, and those claims and interests may also be canceled for little or no consideration.

The report of the Company's independent registered public accounting firm that accompanies its audited consolidated financial statements in this Annual Report on Form 10-K contains an explanatory paragraph regarding the substantial doubt about the Company's ability to continue as a going concern. The consolidated financial statements do not include any adjustments that might result from the outcome of the going concern uncertainty.

Under our Credit Agreement and Term Loan Agreement, we are required to deliver audited, consolidated financial statements without a going concern or like qualification or explanation. Because the audit report prepared by our auditors with respect to the financial statements in this Form 10-K includes an explanatory paragraph expressing uncertainty as to our ability to continue as a "going concern," we will be in default under each of the Credit Agreement and Term Loan Agreement on April 14, 2020 when we deliver our financial statements to the lenders under the Credit Agreement and the Term Loan Agreement, respectively. We expect that we will be precluded from drawing additional amounts under the Credit Agreement while the default exists. There is a 30-day grace period related to this covenant in each of the Credit Agreement and the Term Loan Agreement. If we do not obtain a waiver or other suitable relief from the lenders under the Credit Agreement or the Term Loan Agreement before the expiration of the 30-day grace period, an event of default under each of the Credit Agreement and Term Loan Agreement would occur. If an event of default occurs, the lenders could accelerate the loans outstanding under the Credit Agreement and Term Loan Agreement. In addition, if the lenders under our Credit Agreement and Term Loan Agreement accelerate the loans outstanding thereunder, we will then also be in default under the indentures related to our Second Lien Notes and our Unsecured Notes. If we default under the indentures, the holders of the Second Lien Notes and Unsecured Notes could accelerate those notes. At this time, we do not expect to obtain a waiver of this requirement.

Subject to a restructured balance sheet, we believe the long-term outlook for our business is favorable despite the continued uncertainty of gas and oil prices because of our low operating cost and predictable production profile. Our resource base, operational expertise, risk management, including an active hedging program, and disciplined investment of capital provide us with an opportunity to generate significant operating cash flow as we maximize the production and efficiency of our long-lived, low cost assets in the Pinedale field. However, the continued prolonged period of depressed commodity prices and our current levels of indebtedness have caused us to conclude that a significant restructuring of our balance sheet is necessary in order to continue as a going concern. We discuss these matters in further detail under, among other places, in Note 1 to our Consolidated Financial Statements.

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 ("ASC 932") as updated in order to align the reserve calculation and disclosure requirements with those in SEC Release No. 33-8995, Modernization of Oil and Gas Reporting Requirements ("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.

Estimates of proved crude oil and natural gas reserves require significant professional judgment and materially affect the Company's 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. Consequently, 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 SEC Release No. 33-8995 ASC Topic 932, Extractive Activities — Oil and Gas ("ASC 932"). Under this method of accounting, the costs for both successful and unsuccessful 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 on the 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. While the Company does not have any material amounts of unevaluated properties at the current time, it has been a larger consideration in prior years. 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, estimated 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.

Impairment 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 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 of the 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 DD&A rate in subsequent 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 2019, 2018 or 2017.

At March 31, 2020, the future net cash flows, before income tax and the discounted future net cash flows before income tax estimated were \$1.907 billion and \$1.218 billion, respectively. As a result of the decrease in both quantities of oil and gas reserves, as well as the discounted future cash flow estimates, the Company estimates it will record an increased rate of DD&A per Mcfe and require a material impairment charge to its oil and gas properties due to the ceiling test limitation in the quarter ended March 31, 2020.

Deferred Financing Costs. The Company follows ASU No. 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* for its Term Loan Facility, Second Lien Notes, and the Unsecured Notes and includes the costs for issuing debt including issuance discounts as a direct deduction from the carrying amount of the related debt liability.

Additionally, the Company follows ASU No. 2015-15, *Interest – Imputation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line of Credit Arrangements* for its Revolving Credit Facility and includes the costs related to the issuance of the Revolving Credit Facility in Other assets on 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 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.

Revenue Recognition. 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. On January 1, 2018, the Company adopted the new accounting standard, ASC 606 *Revenue from Contracts with Customers* and all related amendments. See Note 2 for additional details and disclosures related to the Company's adoption of this standard.

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 net deferred tax assets as of December 31, 2019. 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 (“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 (“ASC 820”). Under 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 9 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.

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 (“ASC 718”) which requires the measurement and recognition of compensation expense for all share-based payment awards made to employees and directors based on estimated fair values. We also estimate forfeitures at the time of grant and revise those estimates in subsequent periods if actual forfeitures differ from our estimates. Share-based compensation expense recognized under ASC 718 for the years ended December 31, 2019, 2018 and 2017 was \$2.6 million, \$11.8 million and \$40 million, respectively. See Note 7 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.

New Accounting Pronouncements: From time to time, the FASB issues new accounting pronouncements. Updates to the FASB ASC are communicated through issuance of an Accounting Standards Update (“ASU”). Unless otherwise discussed, we believe that the impact of recently issued guidance, whether adopted or to be adopted in the future, is not expected to have a material impact on the consolidated financial statements upon adoption.

Recently Adopted Accounting Pronouncements:

Leases: In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)*, and has subsequently issued several supplemental and/or clarifying ASUs (collectively known as “ASC 842”). The guidance requires lessees 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. ASC 842 also requires 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. The Company adopted ASC 842 and applicable amendments on January 1, 2019, using the modified retrospective approach. The Company elected certain practical expedients and established internal controls and key system functionality to enable the preparation of financial information on adoption.

The adoption of the standard had an effect on the Company's consolidated balance sheets and consolidated statement of operations. The most significant impact was the recognition of right-of-use assets and lease liabilities for operating leases, while accounting for finance leases remained substantially unchanged. Please refer to Note 12 for additional discussion.

Cumulative Effect of Recently Adopted Accounting Pronouncements:

The following table reflects the cumulative impact of the adoption of ASC 842 on January 1, 2019, using the modified retrospective approach:

	December 31, 2018 as reported	Impact of ASC 842 (In thousands)	January 1, 2019 as adjusted
Long-term right-of-use assets	\$ —	\$ 130,649	\$ 130,649
Total assets	1,733,288	130,649	1,863,937
Lease liabilities (current)	—	11,141	11,141
Deferred gain on sale of liquids gathering system	94,636	(94,636)	—
Long-term lease liabilities	—	121,326	121,326
Total liabilities	2,781,910	37,831	2,819,741
Retained earnings (loss)	(3,186,016)	92,818	(3,093,198)
Total shareholders' equity (deficit)	(1,048,622)	92,818	(955,804)
Total liabilities and shareholders' equity (deficit)	1,733,288	130,649	1,863,937

Recent Accounting Pronouncements Not Yet Adopted:

Fair Value Measurements. In August 2018, the FASB issued ASU No. 2018-13, *Fair Value Measurements* (Topic 820): *Disclosure Framework — Changes to the Disclosure Requirements for Fair Value Measurement*. The amendments in this update modify the disclosure requirements on fair value measurements in Topic 820. The ASU is effective for the public companies for fiscal years beginning after December 15, 2019, and interim periods therein. The standard is effective for the Company on January 1, 2020.

Financial Instruments. In June 2016, The FASB issued ASU 2016-13, *Financial Instruments – Credit Losses* (Topic 326), *Measurement of Credit Losses on Financial Instruments* (“ASU 2016-13”). This ASU changes the methodology for measuring credit losses on financial instruments and the timing of when such losses are recorded. ASU 2016-13 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2022 for small reporting companies. The standard is effective for the Company on January 1, 2023. The Company is currently assessing the impact of ASU 2016-13 on its consolidated financial statements.

Income Taxes. In December 2019, the FASB issued authoritative guidance intended to simplify the accounting for income taxes (ASU 2019-12, “Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes”). This guidance eliminates certain exceptions to the general approach to the income tax accounting model, and adds new guidance to reduce the complexity in accounting for income taxes. This guidance is effective for annual periods after December 15, 2020, including interim periods within those annual periods. We are currently evaluating the potential impact of this guidance on our financial statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

As a smaller reporting company, we are not required to provide the information required by this Item.

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 this evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2019.

Ernst & Young LLP, the independent registered public accounting firm that audited the accompanying financial statements included in this Annual Report, has issued an attestation report on the effectiveness of our internal control over financial reporting as of December 31, 2019, as stated in their report which is included herein.

Report of Independent Registered Public Accounting Firm

To the Shareholders and the 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, 2019 and 2018, the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2019, 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, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, 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, 2019, 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 April 14, 2020 expressed an unqualified opinion thereon.

The Company's Ability to Continue as a Going Concern

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 1 to the financial statements, the Company has significant indebtedness, and extremely challenging current market conditions that have had an adverse impact on the Company's business and has stated that substantial doubt exists about the Company's ability to continue as a going concern. Management's evaluation of the events and conditions and management's plans regarding these matters are also described in Note 1. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

Adoption of ASU No. 2016-02, Leases (Topic 842)

As discussed in Notes 1 and 12 to the consolidated financial statements, the Company changed its method of accounting for leases in 2019 due to the adoption of ASU No. 2016-02, Leases (Topic 842).

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.

Denver, Colorado
April 14, 2020

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, 2019, 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, 2019, 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, 2019 and 2018, the related statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2019, and the related notes and our report dated April 14, 2020 expressed an unqualified opinion thereon that included an explanatory paragraph regarding the Company's ability to continue as a going concern.

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

Denver, Colorado
April 14, 2020

ULTRA PETROLEUM CORP. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2019	2018
	(Amounts in thousands of U. S. dollars, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 1,664	\$ 17,014
Restricted cash	1,777	2,291
Oil and gas revenue receivable	71,957	133,042
Joint interest billing and other receivables net of allowances \$11,967 and \$8,350, respectively	6,364	11,348
Derivative asset	32,100	23,374
Income tax receivable	881	6,431
Other current assets	10,746	21,230
Total current assets	125,489	214,730
Oil and gas properties, net, using the full cost method of accounting:		
Proven	1,552,419	1,497,727
Property, plant and equipment	9,779	11,635
Long-term right-of-use assets	119,496	—
Other	8,093	9,196
Total assets	\$ 1,815,276	\$ 1,733,288
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	\$ 13,570	\$ 36,923
Accrued liabilities	42,824	58,574
Production taxes payable	53,428	58,365
Current portion of long-term debt		
Revolving credit facility, at face value	64,700	—
Debt, at face value	1,928,048	7,313
Add: Premium on exchange transaction	203,883	—
Less: Unamortized deferred financing costs and discount	(46,421)	—
Total current portion of long-term debt, net	2,150,210	7,313
Interest payable	29,903	28,672
Capital cost accrual	1,656	15,014
Lease liabilities	11,938	—
Derivative liability	20,692	62,350
Total current liabilities	2,324,221	267,211
Long-term debt		
Revolving credit facility, at face value	—	104,000
Long-term debt, at face value	—	1,932,722
Add: Premium on exchange transaction	—	228,096
Less: Unamortized deferred financing costs and discount	—	(56,650)
Total long-term debt, net	—	2,208,168
Deferred gain on sale of liquids gathering system	—	94,636
Long-term lease liabilities	107,587	—
Other long-term obligations	228,282	211,895
Total liabilities	2,660,090	2,781,910
Commitments and contingencies (Note 14)		
Shareholders' equity:		
Common stock — As of December 31, 2019 no par value; authorized — unlimited; issued and outstanding shares — 197,888,473 and as of December 31, 2018 no par value; authorized — 750,000,000; issued and outstanding shares — 197,383,295	2,140,520	2,137,443
Treasury stock	(49)	(49)
Retained loss	(2,985,285)	(3,186,016)
Total shareholders' deficit	(844,814)	(1,048,622)
Total liabilities and shareholders' equity	\$ 1,815,276	\$ 1,733,288

Approved on behalf of the Board:

/s/ Brad Johnson
President, Chief Executive Officer and Director

/s/ Michael J. Keefe
Director

See accompanying notes to consolidated financial statements.

ULTRA PETROLEUM CORP. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2019	2018	2017
	(Amounts in thousands of U.S. dollars, except per share data)		
Revenues:			
Natural gas sales	\$ 637,007	\$ 722,313	\$ 748,682
Oil sales	97,231	153,534	133,368
Other revenues	7,794	16,652	9,823
Total operating revenues	742,032	892,499	891,873
Expenses:			
Lease operating expenses	70,608	90,290	92,326
Facility lease expense	25,468	25,947	21,749
Production taxes	79,459	93,322	91,067
Gathering fees	78,261	89,294	87,287
Transportation charges	1,496	512	(334)
Depletion, depreciation and amortization	204,227	204,255	161,945
General and administrative	26,551	25,005	39,548
Other operating expenses, net	28,889	9,118	—
Total operating expenses	514,959	537,743	493,588
Operating income	227,073	354,756	398,285
Other (expense) income, net:			
Interest expense, net	(129,398)	(148,316)	(361,367)
Gain (loss) on commodity derivatives	(4,597)	(145,212)	28,412
Deferred gain on sale of liquids gathering system	—	10,553	10,553
Contract settlement income (expense), net	13,468	12,656	(52,707)
Other income (expense), net	392	1,212	(237)
Total other (expense) income, net	(120,135)	(269,107)	(375,346)
Reorganization items, net	—	—	140,907
Income before income tax expense (benefit)	106,938	85,649	163,846
Income tax expense (benefit)	(1,050)	442	(13,294)
Net income	\$ 107,988	\$ 85,207	\$ 177,140
Basic Earnings per Share:			
Net income per common share — basic	\$ 0.55	\$ 0.43	\$ 1.08
Fully Diluted Earnings per Share:			
Net income per common share — fully diluted	\$ 0.55	\$ 0.43	\$ 1.08
Weighted average common shares outstanding — basic	197,651	196,964	163,824
Weighted average common shares outstanding — fully diluted	197,690	197,541	163,976

See accompanying notes to consolidated financial statements.

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, 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
Issuance of common stock upon vesting and settlement of equity awards, net of shares used for tax withholdings	1,361	26,673	(9,580)	—	17,093
Fair value of employee stock plan grants	—	27,278	—	—	27,278
Net income	—	—	177,140	—	177,140
Balances at December 31, 2017	196,347	\$ 2,116,018	\$(3,270,605)	\$ (49)	\$(1,154,636)
Issuance of common stock upon vesting and settlement of equity awards, net of shares used for tax withholdings	1,036	—	(2,379)	—	(2,379)
Issuance of warrants	—	5,786	—	—	5,786
Fair value of employee stock plan grants	—	15,639	—	—	15,639
Initial adoption of ASC 606	—	—	1,761	—	1,761
Net income	—	—	85,207	—	85,207
Balances at December 31, 2018	197,383	\$ 2,137,443	\$(3,186,016)	\$ (49)	\$(1,048,622)
Issuance of common stock upon vesting and settlement of equity awards, net of shares used for tax withholdings	505	—	(75)	—	(75)
Fair value of employee stock plan grants	—	3,077	—	—	3,077
Initial adoption of ASC 842	—	—	92,818	—	92,818
Net income	—	—	107,988	—	107,988
Balances at December 31, 2019	197,888	\$ 2,140,520	\$(2,985,285)	\$ (49)	\$(844,814)

See accompanying notes to consolidated financial statements.

2017 Shareholders' Equity Explanatory Note:

In conjunction with emergence from chapter 11 proceedings in April 2017, the Company issued new common shares of the Company (the "New Equity") to holders of existing pre-petition common shares of the Company (the "Existing Common Shares") at a conversion ratio of 0.521562. As a result, the share counts have been adjusted to reflect this conversion as if it had occurred as of the earliest period presented.

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 Company's prepetition senior 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 completed pursuant to the Plan.

ULTRA PETROLEUM CORP. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2019	2018	2017
	(Amounts in thousands of U.S. dollars)		
Cash provided by (used in):			
Operating activities:			
Net income for the period	\$ 107,988	\$ 85,207	\$ 177,140
Adjustments to reconcile net income to cash provided by operating activities:			
Depletion, depreciation and amortization	204,227	204,255	161,945
Unrealized (gain) loss on commodity derivatives	(54,282)	59,799	(16,966)
Deferred gain on sale of liquids gathering system	—	(10,553)	(10,553)
Stock compensation	2,571	11,825	39,977
Payable-in-kind ("PIK") interest payable	12,867	377	—
Non-cash reorganization items, net	—	—	(453,909)
Amortization of premium on restructuring	(41,774)	(1,083)	—
Amortization of deferred financing costs	12,966	11,210	7,483
Inventory write-down	7,461	—	—
Other	3,153	3,501	(1,047)
Net changes in operating assets and liabilities:			
Accounts receivable	62,452	(46,276)	(14,483)
Other current and non-current assets	3,139	5,630	14,615
Accounts payable	(8,195)	(13,206)	34,349
Accrued liabilities	(15,751)	(20,294)	89,935
Production taxes payable	(4,937)	7,098	7,023
Interest payable	1,251	3,889	36,220
Other long-term obligations	3,730	2,674	4,737
Current taxes payable/receivable	5,550	6,844	(11,198)
Net cash provided by operating activities	302,416	310,897	65,268
Investing Activities:			
Oil and gas property expenditures	(241,134)	(426,166)	(557,029)
Sale of oil and gas properties	—	61,304	114,263
Change in capital cost accrual and accounts payable	(28,516)	(27,322)	20,076
Proceeds from sale of property, plant and equipment	9	2,872	—
Purchase of property, plant and equipment	(511)	(12,398)	(12,621)
Net cash used in investing activities	(270,152)	(401,710)	(435,311)
Financing activities:			
Borrowings under Credit Agreement	712,900	1,020,000	773,000
Payments under Credit Agreement	(752,200)	(916,000)	(773,000)
Borrowings under Term Loan	—	—	975,000
Payments under Term Loan	(7,313)	—	—
Extinguishment of long-term debt (chapter 11)	—	—	(2,459,000)
Proceeds from issuance of Senior Notes	—	—	1,200,000
Deferred financing costs	(1,440)	(9,773)	(73,092)
Shares issued, net of transaction costs	—	—	573,774
Tax withholding on shares settled	(75)	(2,378)	(9,581)
Debt extinguishment costs	—	—	(223,838)
Net cash provided by (used in) financing activities	(48,128)	91,849	(16,737)
(Decrease)/Increase in cash during the period	(15,864)	1,036	(386,780)
Cash, cash equivalents, and restricted cash at beginning of period	19,305	18,269	405,049
Cash, cash equivalents, and restricted cash end of period	<u>\$ 3,441</u>	<u>\$ 19,305</u>	<u>\$ 18,269</u>
Supplemental cash flow disclosures			
Cash paid for:			
Interest	\$ 143,738	\$ 135,230	\$ 317,120
Income taxes	\$ —	\$ —	\$ —
Supplemental non-cash investing and financing activities			
Premium on Exchange Transaction	\$ —	\$ 229,179	\$ —
Principal reduction from exchange transaction	\$ —	\$ (229,179)	\$ —

See accompanying notes to consolidated financial statements.

ULTRA PETROLEUM CORP. AND SUBSIDIARIES
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. and its wholly-owned subsidiaries (collectively the “Company”, “Ultra”, “our”, “we”, or “us”) is an independent oil and gas company engaged in the operation and production, development and 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 operating and developing its long-life natural gas reserves in the Pinedale and Jonah fields of the Green River Basin of Wyoming.

1. SIGNIFICANT ACCOUNTING POLICIES:

Going Concern. As a result of our significant indebtedness and extremely challenging current market conditions that have had an adverse impact on our business, and as a result of our financial condition, substantial doubt exists about our ability to continue as a going concern. A failure by us to comply with our financial covenants or to comply with the other restrictions in our financing agreements is expected to result in reduced borrowing capacity or an event of default, causing our debt obligations under such financing agreements (and any other indebtedness or contractual obligations to the extent linked to it by reason of cross-default or cross-acceleration provisions) to potentially become immediately due and payable. Accordingly, all debt balances as of December 31, 2019 have been classified as current on the consolidated balance sheet.

In February and March 2020, we entered into confidentiality agreements and commenced discussions with certain holders of the Company’s long-term debt and their legal and financial advisors. Negotiations and discussions with certain debtholders and their advisors are ongoing, although as of the date of this filing no definitive agreements have been reached regarding any amendments, restructurings or other transactions.

There can be no assurance that our efforts will result in any agreement or what the terms of any agreement will be. If an agreement is reached and we pursue a restructuring, it may be necessary for us to file a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code or the Canadian Bankruptcy and Insolvency Act in order to implement an agreement through the confirmation and consummation of a plan of reorganization approved by the bankruptcy court in the bankruptcy proceedings. We also may conclude that it is necessary to initiate proceedings under Chapter 11 of the United States Bankruptcy Code to implement a restructuring of our obligations even if we are unable to reach an agreement with our creditors and other relevant parties regarding the terms of such a restructuring. In either case, such a proceeding could be commenced in the near term.

The report of the Company’s independent registered public accounting firm that accompanies its audited consolidated financial statements in this Annual Report on Form 10-K contains an explanatory paragraph regarding the substantial doubt about the Company’s ability to continue as a going concern. The consolidated financial statements do not include any adjustments that might result from the outcome of the going concern uncertainty.

Under our Credit Agreement and Term Loan Agreement, we are required to deliver audited, consolidated financial statements without a going concern or like qualification or explanation. Because the audit report prepared by our auditors with respect to the financial statements in this Form 10-K includes an explanatory paragraph expressing uncertainty as to our ability to continue as a going concern, we will be in default under each of the Credit Agreement and Term Loan Agreement on April 14, 2020 when we deliver our financial statements to the lenders under the Credit Agreement and the Term Loan Agreement, respectively. We expect that we will be precluded from drawing additional amounts under the Credit Agreement while the default exists. There is a 30-day grace period related to this covenant in each of the Credit Agreement and the Term Loan Agreement. If we do not obtain a waiver or other suitable relief from the lenders under the Credit Agreement or the Term Loan Agreement before the expiration of the 30-day grace period, an event of default under each of the Credit Agreement and Term Loan Agreement would occur. If an event of default occurs, the lenders could accelerate the loans outstanding under the Credit Agreement and Term Loan Agreement. In addition, if the lenders under our Credit Agreement and Term Loan Agreement accelerate the loans outstanding thereunder, we will then also be in default under the indentures related to our Second Lien Notes and our Unsecured Notes. If we default under those indentures, the holders of the Second Lien Notes and Unsecured Notes could accelerate those notes. At this time, we do not expect to obtain a waiver of this requirement.

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.

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

Restricted Cash: Restricted cash represents cash received by the Company from production sold where the final distribution of the production revenues is unknown or in dispute.

The Company adopted Accounting Standards Update (“ASU”) 2016-18, Statement of Cash Flows (Topic 230): Restricted Cash and reports the change in cash, cash equivalents, and restricted cash in total on the Consolidated Statement of Cash Flows as of December 31, 2017. See the following table for a reconciliation of cash, cash equivalents, and restricted cash reported within the Consolidated Financial Statements:

Current Presentation	December 31, 2019	December 31, 2018	December 31, 2017
Cash and Cash Equivalents	\$ 1,664	\$ 17,014	\$ 16,631
Restricted Cash	1,777	2,291	1,638
Total cash, cash equivalents, and restricted cash	<u>\$ 3,441</u>	<u>\$ 19,305</u>	<u>\$ 18,269</u>

Accounts Receivable: Accounts receivable are stated at the historical carrying amount net of write-offs and an allowance for uncollectible accounts. Included in the Other operating expenses, net on the Consolidated Statements of Operations is the provision for uncollectible accounts of \$3.3 million for the period ended December 31, 2019. 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.

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

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 (“ASC 932”). Under this method of accounting, the costs of successful and unsuccessful 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. Interest is capitalized on the cost of unevaluated gas and oil properties that are excluded from amortization and actively being evaluated, if any. 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 the 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. While the Company does not have any material amounts of unevaluated properties at the current time, it has been a larger consideration in prior years. 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, estimated 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 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 of the 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 subsequent 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 2019, 2018 or 2017.

Derivative Instruments and Hedging Activities: The Company follows FASB ASC Topic 815, Derivatives and Hedging (“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 8 for additional information).

Deferred Financing Costs: The Company follows ASU No. 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* for its Term Loan Facility, Second Lien Notes, and the Unsecured Notes and includes the costs for issuing debt including issuance discounts, as a direct deduction from the carrying amount of the related debt liability.

Additionally, the Company follows ASU No. 2015-15, *Interest – Imputation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line of Credit Arrangements* for its Revolving Credit Facility and includes the costs related to the issuance of the Revolving Credit Facility in Other assets on the Consolidated Balance Sheets.

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.

Warrants: On December 21, 2018, in connection with the consummation of the Exchange Transaction, the Company issued 10,919,499 new warrants of the Company each entitling the holder thereof to purchase one common share of the Company (each a “Warrant” and collectively, the “Warrants”). The Warrants are initially exercisable for one common share of the Company, no par value, at an initial exercise price of \$0.01 per Warrant. No Warrants will be exercisable until the date on which the volume-weighted average price of the Common Shares is at least \$2.50 per Common Share for 30 consecutive trading days (the “Trading Price Condition”). Subject to the Trading Price Condition, the Warrants are exercisable at the option of the holders thereof from the December 21, 2018 until July 14, 2025, at which time all unexercised Warrants will expire and the rights of the holders of such Warrants to purchase Common Shares will terminate. Under the guidance in ASC 815, the Warrants do not meet the definition of a derivative. The Warrants are classified as equity and recorded at fair value as of the date of issuance on the Company’s Consolidated Balance Sheets and no further adjustments to their valuation are made.

Earnings Per Share: Basic earnings per share is computed by dividing net earnings (attributable to common stockholders) by the weighted average number of common shares outstanding during each period. Diluted earnings 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.

Certain share-based awards subject to 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 market criteria are met. Additionally, certain share-based awards subject to service conditions are considered anti-dilutive if the exercise price exceeds the average market price. Lastly, the Warrants issued in connection with the Exchange Transaction are not included in the diluted earnings per share denominator using the treasury stock method as the Trading Price Condition on the Warrants exceeded the average market price. For the years ended December 31, 2019, 2018 and 2017, the Company had 20.9 million, 14.2 million and 3.9 million, respectively, of shares not included in dilutive earnings per share because the shares would have been anti-dilutive as the exercise price was greater than the average market price of the common shares or the shares are contingently issuable shares.

The following table provides a reconciliation of components of basic and diluted net income per common share:

	December 31,		
	2019	2018	2017
Net income	\$ 107,988	\$ 85,207	\$ 177,140
Weighted average common shares outstanding during the period	197,651	196,964	163,824
Effect of dilutive instruments	39	577	152
Weighted average common shares outstanding during the period including the effects of dilutive instruments	197,690	197,541	163,976
Net income per common share — basic	\$ 0.55	\$ 0.43	\$ 1.08
Net income per common share — fully diluted	\$ 0.55	\$ 0.43	\$ 1.08

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.

Accounting for Share-Based Compensation: The Company measures and recognizes compensation expense for all share-based payment awards made to employees and directors based on estimated fair values in accordance with FASB ASC Topic 718, Compensation – Stock Compensation. We also estimate forfeitures at the time of grant and revise those estimates in subsequent periods if actual forfeitures differ from our estimates.

Fair Value Accounting: The Company follows FASB ASC Topic 820, Fair Value Measurements and Disclosures (“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 9 for additional information.

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.

Revenue Recognition: The Company generally sells oil and natural gas under both long-term and short-term agreements at prevailing market prices. On January 1, 2018, the Company adopted the new accounting standard, ASC 606, Revenue from Contracts with Customers and all related amendments. See Note 2 for additional details and disclosures related to the Company’s revenue recognition.

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.

Capital Cost Accrual: The Company accrues for capital expenditures, including exploration and development costs in the period incurred, while payment may occur in a subsequent period.

Reclassifications: Certain amounts in the financial statements of prior periods have been reclassified to conform to the current period financial statement presentation. These reclassifications had no effect on the reported results of operations.

New Accounting Pronouncements: From time to time, the FASB issues new accounting pronouncements. Updates to the FASB ASC are communicated through issuance of an Accounting Standards Update (“ASU”). Unless otherwise discussed, we believe that the impact of recently issued guidance, whether adopted or to be adopted in the future, is not expected to have a material impact on the consolidated financial statements upon adoption.

Recently Adopted Accounting Pronouncements:

Leases: In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)*, and has subsequently issued several supplemental and/or clarifying ASUs (collectively known as “ASC 842”). The guidance requires lessees 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. ASC 842 also requires 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. The Company adopted ASC 842 and applicable amendments on January 1, 2019, using the modified retrospective approach. The Company elected certain practical expedients and established internal controls and key system functionality to enable the preparation of financial information on adoption.

The adoption of the standard had an effect on the Company’s consolidated balance sheets and consolidated statement of operations. The most significant impact was the recognition of right-of-use assets and lease liabilities for operating leases, while accounting for finance leases remained substantially unchanged. Please refer to Note 12 for additional discussion.

Cumulative Effect of Recently Adopted Accounting Pronouncements:

The following table reflects the cumulative impact of the adoption of ASC 842 on January 1, 2019, using the modified retrospective approach:

	December 31, 2018 as reported	Impact of ASC 842 (In thousands)	January 1, 2019 as adjusted
Long-term right-of-use assets	\$ —	\$ 130,649	\$ 130,649
Total assets	1,733,288	130,649	1,863,937
Lease liabilities (current)	—	11,141	11,141
Deferred gain on sale of liquids gathering system	94,636	(94,636)	—
Long-term lease liabilities	—	121,326	121,326
Total liabilities	2,781,910	37,831	2,819,741
Retained earnings (loss)	(3,186,016)	92,818	(3,093,198)
Total shareholders' equity (deficit)	(1,048,622)	92,818	(955,804)
Total liabilities and shareholders' equity (deficit)	1,733,288	130,649	1,863,937

Recent Accounting Pronouncements Not Yet Adopted:

Fair Value Measurements. In August 2018, the FASB issued ASU No. 2018-13, *Fair Value Measurements* (Topic 820): *Disclosure Framework — Changes to the Disclosure Requirements for Fair Value Measurement*. The amendments in this update modify the disclosure requirements on fair value measurements in Topic 820. The ASU is effective for the public companies for fiscal years beginning after December 15, 2019, and interim periods therein. The Company is currently assessing the impact of this standard on its disclosures. The standard is effective for the Company on January 1, 2020.

Financial Instruments. In June 2016, The FASB issued ASU 2016-13, *Financial Instruments – Credit Losses* (Topic 326), *Measurement of Credit Losses on Financial Instruments* (“ASU 2016-13”). This ASU changes the methodology for measuring credit losses on financial instruments and the timing of when such losses are recorded. For small reporting companies, as defined by the SEC, ASU 2016-13 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2022. The standard is effective for the Company on January 1, 2023. The Company is currently assessing the impact of ASU 2016-13 on its consolidated financial statements.

Income Taxes. In December 2019, the FASB issued authoritative guidance intended to simplify the accounting for income taxes (ASU 2019-12, “Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes”). This guidance eliminates certain exceptions to the general approach to the income tax accounting model, and adds new guidance to reduce the complexity in accounting for income taxes. This guidance is effective for annual periods after December 15, 2020, including interim periods within those annual periods. We are currently evaluating the potential impact of this guidance on our financial statements.

2. REVENUE RECOGNITION:

Revenue from Contracts with Customers

Sales of oil and natural gas are recognized at the point when title and custody (“control”) of the product is transferred to the customer, collectability is reasonably assured, and the performance obligations are satisfied. Virtually all of our contracts’ pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering line or a transmission line, quality of the oil or natural gas, and prevailing supply and demand conditions. As a result, the price we receive for our produced oil and natural gas fluctuates to remain competitive with other available oil and natural gas supplies.

Natural gas sales

We sell natural gas production at the processing plant inlet, the tailgate of the processing plant or at another agreed-upon delivery point, as specified in the contracts with our customers. The production is sold at set volumes and we collect either (i) an agreed upon index price, (ii) a specific index price adjusted for pricing differentials, or (iii) a set price. We recognize revenue at the net price received when control transfers to the purchaser at the agreed-upon delivery point. For these contracts, we have concluded that the Company is the principal for our net revenue interest share of the volumes being sold. Gathering fees are incurred prior to the customer taking control of the product, are not considered to be promised services, and are not included in the transaction price; thus, they are presented as expenses in the Consolidated Statement of Operations.

Our working interest partners are considered the principal for their working interest shares. They have the option to take their gas volumes in kind. The Company may act as an agent and market the other partners' share of the natural gas production from wells we operate. If it does so, the Company is considered the agent and revenue is recorded at the Company's net revenue interest in the production.

Oil sales

We sell oil production at either (a) a lease automatic custody transfer meter, (b) a tank battery, or (c) a delivery point downstream, as specified in the contracts with our customers. The production is sold at set volumes and we collect either (i) an agreed upon index price, (ii) a specific index price adjusted for pricing differentials, or (iii) a set price. We recognize revenue at the point when the customer takes control of the product. For these contracts, we have concluded that the Company is the principal for its net revenue interest share of the volumes being sold. Gathering fees are performed prior to the customer taking control of the product, are not considered to be promised services, and are not included in the transaction price; thus, they are presented as expenses in the Consolidated Statement of Operations.

Our working interest partners are considered the principal for their working interest shares. They have the option to take their oil volumes in kind. The Company acts as an agent and markets the other partners' share of almost all oil production from wells we operate. In these situations, the Company is considered the agent and revenue is recorded at the Company's net revenue interest in the production.

Other revenues

Our other revenue is comprised of fees paid to us by the operators of the gas processing plants where our gas is processed when control is transferred upon completion of the processing service. The Company is considered the principal, and revenue is recognized at the point in time that the control is transferred.

Transaction price allocated to remaining performance obligations

A significant number of our product sales are short-term in nature with a contract term of one year or less at index-based prices. For those contracts, we have utilized the practical expedient in ASC 606-10-50-14 exempting the Company from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

For our product sales that have a contract term greater than one year, we have utilized the practical expedient in ASC 606-10-50-14(a) which states that the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these sales contracts, each unit of product generally represents a separate performance obligation; therefore, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required.

Contract balances

Under our product sales contracts, we invoice customers once our performance obligations have been satisfied, at which point payment is unconditional. Accordingly, our product sales contracts do not give rise to contract assets or liabilities under ASC 606.

Prior-period performance obligations

We record revenue in the month when control is transferred to the purchaser and all contractual obligations are satisfied. However, settlement statements for certain natural gas sales may not be received for 30 to 90 days after the date production is delivered. Consequently, we are required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. We record the differences between our estimates and the actual amounts received for product sales in the month that payment is received from the purchaser. We have existing internal controls for our revenue estimation process and related accruals, and any identified differences between our revenue estimates and actual revenue received historically have been insignificant. Revenue recognized related to performance obligations satisfied in prior reporting periods was not material for the years ended December 31, 2019 and 2018.

3. 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,	
	2019	2018
Asset retirement obligations at beginning of period	\$ 179,462	\$ 173,100
Accretion expense	13,255	12,342
Liabilities incurred	1,511	3,558
Liabilities divested (1)	—	(9,372)
Liabilities settled	—	(70)
Revisions of estimated liabilities	(40)	(96)
Asset retirement obligations at end of period	194,188	179,462
Less: current asset retirement obligations	(193)	(193)
Long-term asset retirement obligations (2)	<u>\$ 193,995</u>	<u>\$ 179,269</u>

- (1) During the year ended December 31, 2018, the Company divested certain non-core properties in Utah.
(2) Included in Other long-term obligations in the Consolidated Balance Sheet.

4. OIL AND GAS PROPERTIES:

	December 31,	
	2019	2018
Proven Properties:		
Acquisition, equipment, exploration, drilling and environmental costs	\$ 11,820,392	\$ 11,577,281
Less: Accumulated depletion, depreciation and amortization	(10,267,973)	(10,079,554)
Total Oil and gas properties, net	<u>1,552,419</u>	<u>1,497,727</u>

On a unit basis, DD&A was \$0.85, \$0.74 and \$0.59 per Mcfe for the years ended December 31, 2019, 2018 and 2017, respectively.

Impairment of Oil and Gas Properties in the quarter ended March 31, 2020

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.

In order to fulfill the obligation to evaluate the full cost ceiling and to calculate DD&A of its oil and gas properties, the Company is required to estimate its reserves on a quarterly basis. The estimated proven oil and gas reserves considers the estimated future production based on the most current well information available including decline rate changes causing downward revisions and updated pricing in accordance with SEC requirements. The reserve estimated as of March 31, 2020 were prepared by Netherland, Sewell & Associates, Inc. The comparable calculated average SEC prices utilized in the preparation of the reserves as of March 31, 2020 were \$2.07 per Mcf and \$55.35 per Bbl. These prices represent a decrease of 15% and <1% for natural gas and oil, respectively, as compared to the pricing utilized as of December 31, 2019.

As a result of the decrease in both quantities of oil and gas reserves, as well as the discounted future cash flow estimates, the Company estimates it will record an increased rate of DD&A per Mcfe and require a material impairment charge to its oil and gas properties due to the ceiling test limitation as of March 31, 2020.

5. PROPERTY, PLANT AND EQUIPMENT:

	December 31,			
	2019		2018	
	Cost	Accumulated Depreciation	Net Book Value	Net Book Value
Computer equipment	2,893	(2,349)	544	619
Office equipment	277	(221)	56	65
Leasehold improvements	264	(206)	58	86
Land	2,437	—	2,437	2,437
Production and other equipment	20,221	(13,537)	6,684	8,428
Property, plant and equipment, net	<u>\$ 26,092</u>	<u>\$ (16,313)</u>	<u>\$ 9,779</u>	<u>\$ 11,635</u>

6. DEBT:

	December 31, 2019			
	Principal (1)	Unamortized Deferred Financing Costs and Discounts (2)	Unamortized Premium on Exchange Transaction	Carrying Value
Credit Agreement, secured, due January 2022	\$ 64,700	\$ —	\$ —	\$ 64,700
Term Loan, secured, due April 2024	968,756	(22,498)	—	946,258
Second Lien Notes, secured, due July 2024	583,853	—	203,883	787,736
6.875% Unsecured Notes due April 2022	150,439	(11,146)	—	139,293
7.125% Unsecured Notes due April 2025	225,000	(12,777)	—	212,223
Total	<u>\$ 1,992,748</u>	<u>\$ (46,421)</u>	<u>\$ 203,883</u>	<u>\$ 2,150,210</u>

(1) Includes PIK interest on the Term Loan and Second Lien Notes of \$1.1 million and \$11.8 million, respectively.

(2) Deferred financing costs related to the Revolving Credit Facility are reported within Other assets on the consolidated balance sheet, rather than as a reduction of the carrying amount of long-term debt.

	December 31, 2018			
	Principal	Unamortized Deferred Financing Costs and Discounts (1)	Unamortized Premium on Exchange Transaction	Carrying Value
Credit Agreement, secured, due January 2022	\$ 104,000	\$ —	\$ —	\$ 104,000
Term Loan, secured, due April 2024	975,000	(26,874)	—	948,126
Second Lien Notes, secured, due July 2024	545,000	—	228,096	773,096
6.875% Unsecured Notes due April 2022	195,035	(15,168)	—	179,867
7.125% Unsecured Notes due April 2025	225,000	(14,608)	—	210,392
	<u>\$ 2,044,035</u>	<u>\$ (56,650)</u>	<u>\$ 228,096</u>	<u>\$ 2,215,481</u>
Less: Current maturities	7,313	—	—	7,313
Total Long-term debt	<u>\$ 2,036,722</u>	<u>\$ (56,650)</u>	<u>\$ 228,096</u>	<u>\$ 2,208,168</u>

(1) Deferred financing costs related to the Revolving Credit Facility are reported within Other assets on the consolidated balance sheet, rather than as a reduction of the carrying amount of long-term debt.

Aggregate maturities of debt at December 31,		
2020 (1)	\$	1,992,748
2021	\$	—
2022 (2)	\$	—
2023	\$	—
2024	\$	—
Beyond 5 years	\$	—
Total	\$	1,992,748

- (1) As previously noted, the audit report prepared by the Company's independent registered public accounting firm includes an explanatory paragraph expressing uncertainty as to our ability to continue as a going concern. This is a default under each of the Credit Agreement and Term Loan Agreement on April 14, 2020 when we deliver our financial statements to the lenders under the Credit Agreement. As a result, we have reclassified our total outstanding debt as short-term as of December 31, 2019.
- (2) In connection with the Exchange Transaction, the Company entered into the Term Loan Amendment, which among other things, included a prohibition on repurchasing more than \$50 million of the 6.875% Unsecured Notes due 2022 or the 7.125% Unsecured Notes due 2025 at their respective maturity dates or within one year thereof.

Ultra Resources, Inc.

Credit Agreement. Ultra Resources Inc., a Delaware corporation and wholly-owned subsidiary of the Company ("Ultra Resources"), entered into a Credit Agreement (as amended, the "Credit Agreement") as the borrower with the Company and UP Energy Corporation, as parent guarantors, with Bank of Montreal, as administrative agent (the "RBL Administrative Agent"), and with the other lenders party thereto from time to time (collectively, the "RBL Lenders"), providing for a revolving credit facility (the "Revolving Credit Facility") subject to a borrowing base redetermination, which limits the aggregate amount of first lien debt under the Revolving Credit Facility and Term Loan Agreement (as defined below).

On February 14, 2020, Ultra Resources entered into a Sixth Amendment to the Credit Agreement (the "Sixth Amendment") with the RBL Administrative Agent and the RBL Lenders party thereto. Pursuant to the Sixth Amendment and the spring 2020 borrowing base redetermination, the Borrowing Base (as defined in the Credit Agreement) was reduced, effective April 1, 2020 to \$1.075 billion, with \$100 million attributed to the Revolving Credit Facility. As described in previous periodic reports, the commitment amount for the Revolving Credit Facility was reduced from \$120 million to \$100 million, as established by the Sixth Amendment. Also included in the Sixth Amendment was the reduction of the all times anti-cash hoarding amount to \$15 million and a provision to complete the borrowing base redetermination quarterly. The next scheduled borrowing base redetermination is scheduled to be completed on or before July 1, 2020.

Other provisions of the Credit Agreement, including the recent amendments are described below:

- elimination of all financial maintenance covenants;
- required minimum hedging on projected natural gas volumes for at least 50% through March 31, 2020, and no minimum hedging requirements exist thereafter;
- limitation of capital expenditures of \$65 million, \$10 million and \$5 million, for the quarters ended September 30, 2019, December 31, 2019, and quarterly thereafter, with the ability to carryforward unused amounts up to \$5 million in aggregate; and
- ability to repurchase indebtedness, including borrowings under the Company's Senior Secured Term Loan, Senior Secured Second Lien Notes, 6.875% Senior Notes due 2022 and 7.125% Senior Notes due 2025 under certain circumstances, including having no amounts drawn on the Revolving Credit Facility, the Company having established adequate cash reserves, satisfaction of a first lien incurrence test, each as set forth in the Fifth Amendment, and compliance with the Company's other debt documents. The Term Loan and the Second Lien Notes continue to have prohibitions against the use of cash to repurchase debt. Therefore, in order for the Company to utilize this provision provided by the Credit Agreement, the Company would have to receive additional approval from both the Term Loan Lenders (as defined below) and the holders of the Second Lien Notes.

As of December 31, 2019, Ultra Resources had \$64.7 million of outstanding borrowings under the Revolving Credit Facility, plus an outstanding Letter of Credit of \$6.7 million, with total commitments of \$200.0 million. Availability under the Revolving Credit Facility is the undrawn portion of the commitment, plus the unrestricted cash of the Company, and net of any outstanding letters of credit outstanding for a total availability of \$130.3 million as of December 31, 2019.

The Company believes there is substantial doubt that its projected cash flows from operations and available liquidity under the Sixth Amendment will be adequate to meet its obligations for the ensuing twelve months from the date of this report.

The next scheduled borrowing base redetermination will be July 1, 2020, as noted above, and then continue on a quarterly basis thereafter. To the extent future commitments under the Credit Agreement decreases below the outstanding balance of the Revolving Credit Facility, because of a downward redetermination of the borrowing base and commitment amount, the Company would be required to enter into a mandatory repayment schedule to satisfy the deficiency. Should the lenders not support such a repayment schedule, in month liquidity for the Company could be inadequate to meet obligations on a timely basis.

In the event that the borrowing base is reduced to an amount that is less than the outstanding borrowings under the Term Loan Agreement, then commitments under the Revolving Credit Facility would be reduced to zero and Ultra Resources would become subject to additional coverage tests under the Term Loan Agreement. Among these new requirements is an asset coverage test and, if not satisfied, Ultra Resources would be required to make mandatory prepayments to the Term Loan Lenders in order to cure any deficiency. Failure to make such required payments would result in an Event of Default under the Term Loan Agreement.

The Revolving Credit Facility has \$35.0 million of the commitments available for the issuance of letters of credit. 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 based upon the borrowing base utilization grid. The applicable margin increases by 25 basis points in the event the Company's consolidated net leverage ratio, as defined, exceeds 4.00 to 1.00.

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 Revolving Credit Facility loans mature on January 12, 2022.

As noted above, the Fifth Amendment established a maximum capital expenditure level. Per the definition of maximum capital expenditures in the Fifth Amendment, the Company expended \$6.8 million in the quarter ended December 31, 2019, and \$53.7 million in the quarter ended September 30, 2019, resulting in a \$5 million carryover as of December 31, 2019.

The Revolving Credit Facility also contains customary affirmative and negative covenants, including, 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. As of December 31, 2019, Ultra Resources was in compliance with its debt covenants under the Revolving Credit Facility. Subsequent to December 31, 2019, the audit report the Company received with respect to its consolidated financial statements contains an explanatory paragraph expressing uncertainty as to the Company's ability to continue as a going concern, the delivery of which constitutes a default under the Credit Agreement.

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

Term Loan. Ultra Resources, entered into a Term Loan Agreement (the "Term Loan Agreement") as the borrower with the Company and UP Energy Corporation, as parent guarantors, with Barclays Bank PLC("Barclays"), as administrative agent (the "Term Loan Administrative Agent"), and with the other lenders party thereto from time to time (collectively, the "Term Loan Lenders"), providing for a term loan credit facility. As of December 31, 2019, Ultra Resources had a balance of approximately \$968.8 million in borrowings, including \$1.1 million PIK interest.

In December 2018, Ultra Resources and the parent guarantors entered into the First Amendment to the Term Loan Agreement (the "Term Loan Amendment") with the Term Loan Administrative Agent and the Term Loan Lenders party thereto. Pursuant to the Term Loan Amendment, the parties agreed, among other things, to amend the Term Loan Agreement to permit the issuance of the Second Lien Notes and the 2018 Exchange Transaction (as defined below), to increase the interest rate payable by 100 basis points, such increase comprising 75 basis points payable in cash and 25 basis points payable in kind, and to revise certain covenants and other provisions of the Term Loan Agreement, including, but not limited to:

- introducing call protection, with the remaining term of the call protection at 101% until December 21, 2020;
- restrictions on the Revolving Credit Facility; including amendments and refinancing of the Revolving Credit Facility as more thoroughly described in the Term Loan Amendment;

- deleting the ability to increase commitments under the Term Loan;
- collateral coverage established at 95% of total PV-9 of Proven Reserves (as defined in the Term Loan Agreement);
- removing the ability to create, invest in and utilize unrestricted subsidiaries;
- prohibiting the repurchase of more than \$50 million of the 2022 Notes (as defined below) or the 2025 Notes (as defined below) at their respective maturity dates or within one year thereof;
- further limiting the Company's ability to incur unsecured debt, repay junior debt, and make restricted payments and investments as more thoroughly described in the Term Loan Amendment; and
- providing the ability for the Company to exchange unsecured borrowings to third lien debt within a construct as described in the Term Loan Amendment.

Borrowings under the Term Loan Agreement bear interest at a rate equal to either (a) a customary London interbank offered rate plus 400 basis points or (b) the base rate plus 300 basis points, in each case, of which 25 basis points of the applicable margin is payable in-kind ("PIK") solely upon election by Ultra Resources. During 2019, the Company elected the PIK option for several of its selected interest payments. In the third quarter 2019, the Company began electing not to utilize this PIK option.

Beginning in June 2019, the borrowings under the Term Loan Agreement amortize in equal quarterly installments in aggregate annual amounts equal to 0.25% of the initial aggregate principal amount. Remaining borrowings under the Term Loan Agreement mature on April 12, 2024.

Borrowings under the Term Loan Agreement are 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 conditions including a situation in which the Revolving Credit Facility no longer exist, there is a prepayment requirement if the asset coverage ratio is less than 2.0 to 1.0. To the extent any mandatory prepayments equal to six monthly payments are required in order to attain compliance, with such amounts being applied to prepay the borrowings under the Term Loan Agreement.

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, 2019, Ultra Resources was in compliance with all of its debt covenants under the Term Loan Agreement. Subsequent to December 31, 2019, the audit report the Company received with respect to its consolidated financial statements contains an explanatory paragraph expressing uncertainty as to the Company's ability to continue as a going concern, the delivery of which constitutes a default under the Term Loan Agreement.

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.

Second Lien Notes. As of December 31, 2019, Ultra Resources had approximately \$583.9 million, including \$11.8 million of PIK interest, in outstanding borrowings of Senior Secured Second Lien Notes (the "Second Lien Notes") pursuant to the Indenture, dated December 21, 2018 (the "Second Lien Notes Indenture"), with Ultra Resources, as issuer, the Company and its other subsidiaries, as guarantors, and Wilmington Trust, National Association, as trustee and collateral agent.

Interest on the Second Lien Notes accrues at (i) an annual rate of 9.00% payable in cash and (ii) an annual rate of 2.00% PIK. The cash interest payment dates for the Second Lien Notes are January 15 and July 15 of each year, commencing in July 2019. The Company has accounted for such PIK interest as an increase to the principal outstanding. The Second Lien Notes will mature on July 12, 2024.

The Second Lien Notes are senior secured obligations of Ultra Resources and rank senior in right of payment to all of its existing and future unsecured senior debt, to the extent of the value of the collateral pledged under the Second Lien Notes Indenture and related collateral arrangements, senior in right of payment to all of its future subordinated debt, and junior in right of payment to all of its existing and future secured debt of senior priority, to the extent of the value of the collateral pledged thereby. The Second Lien Notes are secured by second priority security interests in substantially all assets of the Company. Payment by Ultra Resources of all amounts due on or in respect of the Second Lien Notes and the performance of Ultra Resources under the Indenture are initially guaranteed by the Company.

Prior to December 21, 2021, 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 Second Lien Notes in an amount no greater than the net cash proceeds of certain equity offerings at a redemption price of 111.000% of the principal amount of the Second Lien Notes, plus accrued and unpaid interest (including PIK interest), if any, to the date of redemption, if at least 65% of the original principal amount of the Second Lien Notes remains outstanding and the redemption occurs within 180 days of the closing of such equity offering. In addition, before December 21, 2019, Ultra Resources may redeem all or a part of the Second

Lien 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 (including PIK interest), if any, to the redemption date. In addition, on or after December 21, 2021, Ultra Resources may redeem all or a part of the Second Lien Notes at redemption prices (expressed as percentages of principal amount) equal to 105.500% for the twelve-month period beginning on December 21, 2021, 102.750% for the twelve-month period beginning December 21, 2022, and 100.000% for the twelve-month period beginning December 21, 2023 and at any time thereafter, plus accrued and unpaid interest (including PIK interest), if any, to the applicable redemption date on the Second Lien Notes.

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

The Second Lien Notes 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 or redeem indebtedness; (iii) create or incur certain liens; (iv) enter into affiliate agreements; (v) pay cash dividends, (vi) change the nature of its business or operations, (vii) make certain types of investments, (viii) enter into agreements that restrict distributions from certain restricted subsidiaries and the consummation of mergers and consolidations; (ix) consolidate, merge or transfer all or substantially all of the assets of the Company or any Restricted Subsidiary (as defined in the Second Lien Notes Indenture); and (x) create unrestricted and foreign subsidiaries. The covenants in the Second Lien Notes Indenture are subject to important exceptions and qualifications. Subject to conditions, the Second Lien Notes Indenture provides that the Company and its subsidiaries will no longer be subject to certain covenants when the Second Lien Notes receive investment grade ratings from any two of S&P Global Ratings, Moody's Investors Service, Inc., and Fitch Ratings, Inc.

The Second Lien Notes Indenture contains customary events of default. Unless otherwise noted in the Second Lien Notes Indenture, upon a continuing event of default, 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 Second Lien 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 Second Lien Notes Indenture) or group of Restricted Subsidiaries (as defined in the Second Lien Notes Indenture), that taken together would constitute a Significant Subsidiary, will automatically cause the Second Lien Notes to become due and payable.

Senior Unsecured Notes. At December 31, 2019, Ultra Resources had approximately \$150.4 million of the 6.875% Senior Notes due 2022 (the "2022 Notes") and \$225.0 million of the 7.125% Senior Notes due 2025 (the "2025 Notes", and together with the 2022 Notes, the "Unsecured Notes") outstanding. The Unsecured Notes are treated as a single class of securities under the Unsecured Notes Indenture.

In December 2018, the Company exchanged (i) \$505 million aggregate principal amount, or 72.1%, of the 2022 Notes, and (ii) \$275 million aggregate principal amount, or 55%, of the 2025 Notes of Ultra Resources for (a) \$545.0 million aggregate principal amount of new Second Lien Notes, and (b) an aggregate of 10,919,499 Warrants (such transaction, the "2018 Exchange Transaction").

Then in the first quarter of 2019, the Company entered into an incremental note exchange transaction that provided for the exchange of \$44.6 million aggregate principal amount of 2022 Notes for \$27.0 million aggregate principal amount of Second Lien Notes (together with the 2018 Exchange Transaction, the "Exchange Transactions"), as allowed by the Second Lien Notes Indenture.

The Company evaluated the accounting treatment of the Exchange Transactions under ASC 470, *Debt*. The portion of the senior Unsecured Notes which were exchanged for Second Lien Notes was accounted for as a troubled debt restructuring ("TDR"). The amount of extinguished debt is amortized over the remaining life of the Second Lien Notes using the effective interest method and recognized as a reduction to interest expense. As a result, our reported interest expense following the Exchange Transactions will be significantly less than the contractual cash interest payments throughout the term of the Second Lien Notes.

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 Unsecured Notes from the issue date until maturity.

The Unsecured Notes Indenture contains customary events of default. Unless otherwise noted in the Unsecured Notes Indenture, upon a continuing event of default, the Trustee, by notice to the Company, or the holders of at least 25% in principal amount of the then outstanding Unsecured Notes, by notice to the Company and the Trustee, may, declare the Unsecured 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 Unsecured Notes Indenture) or group of Restricted Subsidiaries (as defined in the Unsecured Notes Indenture), that taken together would constitute a Significant Subsidiary, will automatically cause the Unsecured Notes to become due and payable.

7. EQUITY COMPENSATION:

2017 Stock Incentive Plan

In April 2017, the Ultra Petroleum Corp. 2017 Stock Incentive Plan (the “Plan”) was established by our board of directors (the “Board”) pursuant to which 7.5% of the equity of the 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 Company (the “Reserve”).

In June 2018, each of the Board and the Compensation Committee of the Board (the “Committee”) approved an amendment and restatement of the Ultra Petroleum Corp. 2017 Stock Incentive Plan (as amended and restated, the “A&R Stock Incentive Plan”). The A&R Stock Incentive Plan amends and restates the 2017 Stock Incentive Plan to, among other things:

- provide that consultants, independent contractors and advisors are eligible to participate and receive equity awards in the A&R Stock Incentive Plan;
- limit the aggregate incentive awards available to be granted to any outside director during a single calendar year to a maximum of \$750,000;
- revise the definition of a Change of Control (as defined in the A&R Stock Incentive Plan) to exclude a change in a majority of the members on the Board;
- provide that, with respect to awards granted on or after June 8, 2018, no such awards will vest solely as a result of a Change of Control unless expressly provided otherwise in the applicable grant agreement or unless otherwise determined by the Committee; and
- make certain other changes related to revisions to the U.S. Internal Revenue Code.

There are several components to the Plan that are described below. Various types of equity awards have been granted by the Company in different periods.

As of December 31, 2019, the Company had the following securities issuable pursuant to outstanding award agreements or reserved for issuance under the Company’s previously approved equity incentive plans. Upon exercise, shares issued will be newly issued shares or shares issued from treasury.

<u>Plan Category</u>	<u>Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans</u>
	(000's)
Equity compensation plans approved by security holders	12,588
Equity compensation plans not approved by security holders	n/a
Total	12,588

Performance Share Units:

The Company grants performance share units (“PSUs”) to eligible employees as part of its Plan. For purposes of ASC 718, when vesting of an equity award is dependent on a specific share value or the value of a company’s total equity, the award is considered to be subject to a “market condition”. ASC 718 requires the impact of the market condition to be considered when estimating the fair value of the equity award. As a result, we have used a Monte Carlo simulation model to estimate the fair value of the equity awards that include a market condition.

ASC 718 requires the expense for an award of equity 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) the award’s derived service period. The Company uses a lattice model to determine the derived service period which 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.

During 2017, management incentive grants (the “Initial MIP Grants”) were made to members of the Board, officers, and other employees of the Company subject to the conditions and 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 volume 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 April 12, 2023, such

Initial MIP Grants shall automatically expire. 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.

In July 2018, the Company offered the recipients of the Initial MIP Grants an opportunity to exchange the unvested portion of their Initial MIP Grants for new equity awards of time-based restricted stock units ("RSUs") effective July 31, 2018 on a one-for-one basis (the "Initial MIP Exchange"). The RSUs granted as part of the Initial MIP Exchange are time-based awards and vest in equal tranches on May 25, 2019, May 25, 2020, and May 25, 2021. Under FASB ASC Topic 718, *Compensation Cost – Stock Compensation* ("ASC 718"), the cancellation of an outstanding award of equity compensation followed by the issuance of a replacement award is treated as a modification of the original award. The Initial MIP Exchange was considered a 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 exceeded the fair value prior to modification, incremental expense is generated and recognized over the remaining vesting period. This incremental expense is reflected in the pre-tax equity compensation expense described below.

In March 2019, additional Initial MIP Grants were exchanged for new equity awards of time-based and performance-based restricted stock units (collectively with the Initial MIP Exchange, the "MIP Exchanges"). The Company evaluated the cancellation of an outstanding award of equity compensation followed by the issuance of a replacement award under ASC 718. For the March 2019 modification, the fair value of the equity award was assessed both prior to modification and after modification. Per ASC 718, if the fair value after modification exceeded the fair value prior to modification, incremental expense is generated and recognized over the remaining vesting period. This incremental expense is reflected in the pre-tax equity compensation expense described below. See *Equity Compensation Cost: Expense* below.

Additionally, in 2018 and 2019, the Board approved long-term incentive awards under the Plan 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 market conditions are achieved. The awards cover a performance period of three years and include time-based vesting conditions and market-based measures established by the Committee at the beginning of the three-year period. The fair value of the PSUs is measured at the grant date using the Monte Carlo simulation model and is recognized as compensation expense over the derived service period of the respective awards.

The Company records compensation expense associated with the issuance of PSUs based on the fair value of the awards as of the date of grant. A summary of the status and activity of non-vested PSUs is presented in the following table:

	Year Ended December 31,					
	2019		2018		2017	
	PSUs	Weighted-Average Grant-Date Fair Value	PSUs	Weighted-Average Grant-Date Fair Value	PSUs	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year	3,128,575		3,874,278		—	
Granted	5,310,251	\$ 0.30	2,524,719	\$ 0.62	4,214,902	\$ 11.87
Vested	—	\$ —	(1,769,734)	\$ 11.87	—	\$ —
Forfeited	(1,950,658)	\$ 0.41	(329,156)	\$ 11.87	(214,408)	\$ 11.87
Cancelled	—	\$ —	—	\$ —	(126,216)	\$ 11.87
Cancelled - MIP Exchanges	(581,677)	\$ 11.87	(1,171,532)	\$ 11.87	—	\$ —
Non-vested at end of year	<u>5,906,491</u>		<u>3,128,575</u>		<u>3,874,278</u>	

During the years ended December 31, 2019 and 2017, there were no common stock issued to settle PSUs. Presented below is a summary of the shares of common stock issued to settle PSUs for the year ended December 31, 2018:

	Year Ended December 31, 2018
Shares of common stock issued to settle PSUs (1)	1,769,734
Less: shares of common stock withheld for income and payroll taxes	(733,174)
Net shares of common stock issued	<u>1,036,560</u>

- (1) During the year ended December 31, 2018, the Company issued shares of common stock to settle PSUs that related to awards granted in 2017. The Company and a majority of grant recipients mutually agreed to net share settle a portion of the awards to cover income and payroll tax withholdings in accordance with the Company's Equity Plan and individual award agreements.

Restricted Share Units:

The Company grants RSUs to eligible persons as part of its Plan. Each RSU represents a right to receive one share of the Company's common stock upon settlement of the award at the end of the specified vesting period. Compensation expense for RSUs is recognized over the vesting periods of the respective awards.

The Company records compensation expense associated with the issuance of RSUs based on the fair value of the awards as of the date of grant. The fair value of an RSU is equal to the closing price of the Company's common stock on the day of the grant.

A summary of the status and activity of non-vested RSUs granted to eligible persons is presented in the following table:

	Year Ended December 31,					
	2019		2018		2017	
	RSUs	Weighted-Average Grant-Date Fair Value	RSUs	Weighted-Average Grant-Date Fair Value	RSUs	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year	2,734,709		73,048		—	
Granted	2,677,593	\$ 0.64	1,650,983	\$ 1.89	2,269,199	\$ 13.59
Vested	(1,042,515)	\$ 4.59	—	\$ —	(2,191,297)	\$ 14.07
Forfeited	(704,916)	\$ 6.41	(160,854)	\$ 3.00	(4,854)	\$ 10.31
Granted - MIP Exchanges	581,677	\$ 0.70	1,171,532	\$ 1.77	—	\$ —
Non-vested at end of year	<u>4,246,548</u>		<u>2,734,709</u>		<u>73,048</u>	

A summary of the shares of common stock issued to settle RSUs is presented in the table below:

	Year Ended December 31,		
	2019	2018	2017
Shares of common stock issued to settle RSUs (1)	715,809	—	2,191,297
Less: shares of common stock withheld for income and payroll taxes	(210,631)	—	(837,282)
Net shares of common stock issued	<u>505,178</u>	<u>—</u>	<u>1,354,015</u>

- (1) During the year ended December 31, 2019 and 2017, the Company issued shares of common stock to settle RSUs that related to awards granted in 2017, 2018 and 2019. The Company and a majority of grant recipients mutually agreed to net share settle a portion of the awards to cover income and payroll tax withholdings in accordance with the Company's Equity Plan and individual award agreements.

Equity Compensation Cost:

For the year ended December 31, 2019, the Company recognized \$2.6 million in pre-tax equity compensation expense. For the year ended December 31, 2018, the Company recognized \$11.8 million in pre-tax equity compensation expense. For the year ended December 31, 2017, the Company recognized \$40 million in pre-tax equity compensation expense. As of December 31, 2019, there was \$1.4 million of total unrecognized compensation expense related to non-vested awards, which is being amortized through 2022. Below is a table which summarizes the equity compensation expense for the periods noted.

	Year Ended December 31,		
	2019	2018	2017
Total cost of equity compensation plans	\$ 3,077	\$ 15,639	\$ 53,952
Amounts capitalized in oil and gas properties and equipment	\$ 506	\$ 3,814	\$ 13,975
Amounts charged against income, before income tax benefit	\$ 2,571	\$ 11,825	\$ 39,977
Amount of related income tax benefit recognized in income before valuation allowances	\$ 540	\$ 2,483	\$ 15,927

8. 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, deferred premium puts 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.

Under the Credit Agreement, the Company was subject to minimum hedging requirements through March 31, 2020, as described in Note 6. Beginning April 1, 2020, the Company is no longer be subject to a minimum hedging requirement.

Fair Value of Commodity Derivatives: The Company follows FASB ASC Topic 815, Derivatives and Hedging ("ASC 815"). The Company does not apply hedge accounting to any of its derivative instruments. Instead, in accordance with ASC 815 the derivative contracts are recorded at fair value as derivative assets and liabilities on the Consolidated Balance Sheets and the associated unrealized gains and losses are recorded as current income or expense on the Consolidated Statements of Operations. The Company does not offset the value of its derivative arrangements with the same counterparty. 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, 2019, 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 basis swaps, the Company receives a fixed price for the difference between two sales points for a specified commodity volume over a specified time period. 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. For deferred premium puts, the Company pays the deferred premium in the month of settlement. To the extent the market price is below the put price, the counterparty owes the Company the difference between the market price and put price in the period of settlement. The reference prices of these commodity derivative contracts are typically referenced to index prices published by independent third parties. Refer to Note 9 for more information regarding the fair value of the Company's derivative instruments.

Type	Index	Total Volumes (in millions)	Weighted Average Price Per Unit		Fair Value - December 31, 2019 Asset (Liability)
Natural gas fixed price swaps		(Mmbtu)	(\$/Mmbtu)		
2020	NYMEX-Henry Hub	23.7	\$	2.76	\$ 14,012
Natural gas basis swaps (1)		(Mmbtu)	(\$/Mmbtu)		
2020	NW Rockies Basis Swap	29.9	\$	(0.06)	\$ (16,122)
Crude oil fixed price swaps		(Bbl)	(\$/Bbl)		
2020	NYMEX-WTI	0.5	\$	60.14	\$ 262
Type	Index	Total Volumes (in millions)	Weighted Average Floor Price	Weighted Average Ceiling Price	Fair Value - December 31, 2019 Asset (Liability)
Natural gas collars			(\$/MMBTU)		
2020	NYMEX	60.7	\$ 2.41	\$ 2.88	\$ 11,870
2021	NYMEX	7.2	\$ 2.46	\$ 3.05	\$ 43
Natural gas put options (2)			(\$/MMBTU)		
2020	NYMEX	13.4	\$ 2.42	N/A	\$ 1,386

- (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.
- (2) The Natural gas deferred premium put options include an average deferred premium of \$0.13.

Subsequent to December 31, 2019 through April 10, 2020, the Company entered into the following commodity derivative contracts to manage commodity price risk:

Type	Index	Total Volumes	Weighted Average Price Per Unit
Oil swaps		(Bbl)	(\$/Bbl)
2020	NYMEX WTI	27,300	\$ 60.55

Additionally, the Company terminated approximately \$1.3 million of commodity derivative contracts subsequent to December 31, 2019 and through April 10, 2020.

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, 2019, 2018 and 2017:

Commodity Derivatives:	For the Year Ended December 31,		
	2019	2018	2017
Realized gain (loss) on commodity derivatives-natural gas (1)	\$ (62,573)	\$ (77,031)	\$ 11,446
Realized gain (loss) on commodity derivatives-crude oil(1)	3,694	(8,382)	—
Unrealized gain (loss) on commodity derivatives (1)	54,282	(59,799)	16,966
Total gain (loss) on commodity derivatives	<u>\$ (4,597)</u>	<u>\$ (145,212)</u>	<u>\$ 28,412</u>

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

9. FAIR VALUE MEASUREMENTS:

As required by FASB ASC Topic 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	\$ —	\$ 32,100	\$ —	\$ 32,100
Long-term derivative asset (1)	—	1,516	—	1,516
Total derivative instruments	<u>\$ —</u>	<u>\$ 33,616</u>	<u>\$ —</u>	<u>\$ 33,616</u>
Liabilities:				
Current derivative liability	\$ —	\$ 20,692	\$ —	\$ 20,692
Long-term derivative liability (2)	—	1,473	—	1,473
Total derivative instruments	<u>\$ —</u>	<u>\$ 22,165</u>	<u>\$ —</u>	<u>\$ 22,165</u>

(1) Included in Other assets in the Consolidated Balance Sheet.

(2) Included in Other long-term obligations in the Consolidated Balance Sheet.

The Company entered into commodity derivative contracts and as a result, we expose ourselves to counterparty credit risk. Credit risk is the potential failure of the counterparty to perform under the terms of a derivative contract. In order to minimize our credit risk in derivative instruments, we (i) enter into derivative contracts with counterparties that our management has deemed credit worthy as competent and competitive market makers and (ii) routinely monitor and review the credit of our counterparties. In addition, each of our current counterparties are lenders under our Credit Agreement. We believe that all of our counterparties are of substantial credit quality. Other than as provided in our Credit Agreement, we are not required to provide credit support or collateral to any of our counterparties under our derivative contracts, nor are they required to provide credit support to us. As of December 31, 2019, we did not have any past-due receivables from, or payables to, any of the counterparties of our derivative contracts. Refer to Note 8 for additional details about our derivative financial instruments.

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.

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.

	For the Year Ended December 31,			
	2019		2018	
	Principal	Estimated Fair Value	Principal	Estimated Fair Value
Credit Agreement, secured	\$ 64,700	\$ 64,700	\$ 104,000	\$ 104,000
Term Loan, secured due 2024	968,756	566,723	975,000	858,000
Second Lien Notes, secured due 2024	583,853	86,994	545,000	395,125
6.875% Senior, unsecured Notes, due 2022	150,439	18,805	195,035	68,262
7.125% Senior, unsecured Notes, due 2025	225,000	15,750	225,000	69,750
Total debt	\$ 1,992,748	\$ 752,972	\$ 2,044,035	\$ 1,495,137

10. OTHER CURRENT ASSETS:

The following table summarizes the major components of Other current assets included on the consolidated balance sheet:

	December 31, 2019	December 31, 2018
Deposits and retainers	\$ 651	\$ 651
Prepays and others	1,087	1,822
Crude oil	1,032	1,113
Pipe and production equipment	7,976	17,644
Total Other current assets	\$ 10,746	\$ 21,230

During the year ended December 31, 2019, the Company recorded a write-down of pipe and production inventory to the lower of cost or net realizable value. Our inventories are valued at the lower of cost or net realizable value, with cost determined using either the weighted-average cost, including the cost of transportation and storage, and with net realizable value defined as the estimated selling price in the ordinary course of business, less reasonably predictable costs of transportation. Accordingly, the Company recorded a write-down of pipe and production equipment for \$7.5 million. The expense is reported as Other operating expenses on the consolidated statement of operations. The pipe and production equipment and crude oil inventory has been reclassified to Other current assets as of December 31, 2019 and 2018.

11. INCOME TAXES:

Income before income tax benefit is as follows:

	Year Ended December 31,		
	2019	2018	2017
United States	\$ 108,575	\$ 86,242	\$ (197,136)
Foreign	(1,637)	(593)	360,982
Total	<u>\$ 106,938</u>	<u>\$ 85,649</u>	<u>\$ 163,846</u>

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

	Year Ended December 31,		
	2019	2018	2017
Current tax:			
U.S. federal, state and local	\$ (1,050)	\$ 433	\$ (13,296)
Foreign	—	9	2
Total current tax provision (benefit)	(1,050)	442	(13,294)
Deferred tax:			
Foreign	—	—	—
Total deferred tax expense	—	—	—
Total income tax provision (benefit)	<u>\$ (1,050)</u>	<u>\$ 442</u>	<u>\$ (13,294)</u>

The income tax provision (benefit) from operations differs from the amount that would be computed by applying the U.S. federal income tax rate of 21% to pretax income as a result of the following:

	Year Ended December 31,		
	2019	2018	2017
Income tax provision computed at the U.S. statutory rate	\$ 22,457	\$ 17,986	\$ 57,346
State income tax (benefit) provision net of federal effect	—	—	(25,519)
Valuation allowance	(31,733)	(30,723)	(562,491)
Tax effect of rate change	—	—	463,113
Sale of non-core assets	—	5,863	130,552
Foreign rate differential	(98)	(36)	(3,150)
Reorganization items	220	216	(89,327)
Equity compensation	1,747	2,689	10,778
Disallowed interest	5,799	700	—
Other, net	558	3,747	5,404
Total income tax provision (benefit)	<u>\$ (1,050)</u>	<u>\$ 442</u>	<u>\$ (13,294)</u>

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,	
	2019	2018
Deferred tax assets:		
Property and equipment	\$ —	\$ 33,953
Deferred gain	—	19,874
U.S. federal tax credit carryforwards	512	512
U.S. interest carryforwards	27,949	5,931
U.S. net operating loss carryforwards	480,673	462,401
Non-U.S. net operating loss carryforwards	8,868	7,048
Asset retirement obligations	40,780	37,687
Derivative instruments, net	—	8,995
Debt financing	81,394	92,706
Incentive compensation	2,956	5,370
Lease liabilities	25,452	—
Other, net	3,143	2,148
Total deferred tax assets, gross	671,727	676,625
Valuation allowance	(625,400)	(676,625)
Net deferred tax assets	\$ 46,327	\$ —
Deferred tax liabilities:		
Derivative instruments, net	\$ 2,404	\$ —
Property and equipment	18,828	—
Right-of-use assets	25,095	—
Net tax liabilities	\$ 46,327	\$ —
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, 2019 and 2018, the Company recorded a valuation allowance against certain deferred tax assets of \$625.4 million and \$676.6 million, 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 \$2.3 billion as of December 31, 2019, which may be carried forward to offset taxable income generated in future years and, as a result of the CARES Act, may be carried back to any of the five years preceding the taxable year in which the net operating loss was generated to the extent generated in 2018, 2019 or 2020. If the net operating loss carryforwards and carrybacks are unutilized, they will expire between 2033 and 2037 for net operating losses generated in tax years 2017 and earlier. Federal net operating losses generated in tax years 2018 and later carry forward indefinitely and, if generated in taxable years beginning after 2020, are limited to 80% of taxable income, if utilized. The Company has immaterial Canadian Federal and Provincial and U.S. State tax net operating loss carry forwards that it does not expect to utilize before they expire, as the Company has minimal or no activity in these jurisdictions. 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, 2019.

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, as well as an income tax return in Canada. With certain exceptions, the income tax years 2016 through 2019 remain open to examination by the major taxing jurisdictions in which the Company has

business activity. The Company is under audit in Canada for tax years 2015, 2016, and 2017. 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 Act was enacted into law. Further guidance and clarifications continue to be issued regarding the regulations and provisions of the Tax Act. The Company will continue to monitor these new regulations and analyze their applicability and impact on the Company.

On March 27, 2020, President Trump signed into U.S. federal law the CARES Act, which is aimed at providing emergency assistance and health care for individuals, families, and businesses affected by the COVID-19 pandemic and generally supporting the U.S. economy. The CARES Act, among other things, includes provisions relating to refundable payroll tax credits, deferment of employer side social security payments, net operating loss carryback periods, alternative minimum tax credit refunds, modifications to the net interest deduction limitations and technical corrections to tax depreciation methods for qualified improvement property. In particular, under the CARES Act, (i) for taxable years beginning before 2021, net operating loss carryforwards and carrybacks may offset 100% of taxable income, (ii) NOLs arising in 2018 2019, and 2020 taxable years may be carried back to each of the preceding five years to generate a refund and (iii) for taxable years beginning in 2019 and 2020, the base for interest deductibility is increased from 30% to 50% of EBITDA. We are analyzing the different aspects of the CARES Act to determine whether any specific provisions may impact us.

12. LEASES

The Company adopted ASU 2016-02, Leases (Topic 842), and all applicable amendments as of January 1, 2019. The Company elected to apply the new standard to all leases existing at the date of initial application. Consequently, historical financial information will not be updated, and the disclosures required under the new standard will be provided only for periods beginning January 1, 2019.

The Company determines if an arrangement is a lease at inception. Operating leases are included in long-term right-of-use ("ROU") assets, and long-term lease liabilities on our consolidated balance sheets. ROU assets represent the Company's right to use of an underlying asset for the lease term and lease liabilities represent the Company's obligation to make lease payments arising from the lease. Operating lease ROU assets and liabilities are recognized at commencement date based on the present value of lease payments over the lease term. As most of the Company's leases do not provide an implicit rate, the Company uses its incremental borrowing rate based on the information available at commencement date in determining the present value of lease payments. The operating lease ROU asset also includes any lease payments made and excludes lease incentives. The Company's lease terms may include options to extend or terminate the lease when the Company is reasonably certain that it will exercise that option. Lease expense for lease payments is recognized on a straight-line basis over the lease term. The ROU assets are evaluated for impairment in accordance with ASC 360.

The Company has lease agreements with lease and non-lease components, which are accounted for as a single lease component under the practical expedient provisions of the standard. Additionally, for certain leases, the Company applies a portfolio approach to effectively account for the operating lease ROU assets and liabilities. The portfolio approach was used to assess and determine the incremental borrowing rate with information available at adoption date.

The Company has lease agreements with terms less than one year. For the qualifying short-term leases, the Company elected the short-term lease recognition exemption in which the Company will not recognize ROU assets or lease liabilities, including the ROU assets or lease liabilities for existing short-term leases of those assets in upon adoption.

As of the adoption date, the Company had existing lease agreements with easements in which the Company elected the practical expedient. All new and modified lease agreements with easements completed after the adoption date will be evaluated under the ASC 842.

The Company has operating leases for corporate offices, a liquids gathering system, and certain equipment. The leases have remaining lease terms of one year to nine years. The Company does not include renewal options in the lease term for calculating the lease liability unless it is reasonably certain that it will exercise the option, or the lessor has the sole ability to exercise the option.

The following table summarizes the components of lease cost:

	For the Year Ended December 31, 2019	
	(In thousands)	
Operating lease cost	\$	20,919
Variable lease cost (1)	\$	6,654
Short-term lease cost (2)	\$	15,333
Total lease cost (3)	\$	42,906

- (1) Variable lease payments include additional payments made that were not included in the initial measurement of the ROU asset and corresponding lease liability for agreements with terms longer than 12 months. Variable lease payments relate to the actual volumes transported under certain agreements, and variable utility costs associated with the Company's leased office space. Fluctuations in variable lease payments are driven by actual volumes under long-term agreements.
- (2) Costs associated with short-term lease agreements relate primarily to operational activities where underlying lease terms are less than one year. This amount includes drilling activities, most of which are contracted for 12 months or less. It is expected this amount will fluctuate primarily with the number of drilling rigs the Company is operating under short-term agreements. Additionally, this balance includes approximately \$2.0 million of rig demobilization costs and early termination costs. Drilling contracts that were on a month-to-month basis are excluded from this amount.
- (3) Lease costs are either expensed on the accompanying statements of operations or capitalized on the accompanying balance sheets depending on the nature and use of the underlying ROU asset.

The following table provides supplemental balance sheet information related to the Company's operating leases:

	For the Year Ended December 31, 2019	
	(In thousands)	
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	\$	20,889

The following table provides supplemental cash flow information related to the Company's operating leases:

	December 31, 2019	
	(In thousands)	
Operating Leases		
Operating lease right-of-use assets	\$	119,496
Operating lease liabilities	\$	11,938
Long-term operating lease liabilities		107,587
Total operating lease liabilities	\$	119,525
Weighted Average Remaining Lease Term		
Operating leases		7.85 years
Weighted Average Discount Rate		
Operating leases		7.91%

The following table summarizes the fixed, future minimum rental payments, excluding variable costs, which are discounted by the Company's incremental borrowing rates to calculate the lease liabilities for the Company's operating leases:

	Operating Leases	
	(In thousands)	
For the year ending December 31,		
2020		20,853
2021		20,750
2022		20,326
2023		19,719
2024		19,719
Thereafter		58,520
Total lease payments	\$	159,887
Less: imputed interest		(40,362)
Total	\$	119,525

13. EMPLOYEE BENEFITS:

The Company sponsors a qualified, tax-deferred savings plan in accordance with provisions of Section 401(k) of the Internal Revenue Code (“IRC”) for its employees. Employees may defer 100% of their compensation, subject to limitations established under the IRC. 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 \$2.5 million, \$2.5 million and \$2.4 million for the years ended December 31, 2019, 2018 and 2017, respectively.

14. COMMITMENTS AND CONTINGENCIES:

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. 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 Part I. 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.

Transportation Contract

During our chapter 11 proceedings, 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 has committed to 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 agreement provides 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. The Company has demonstrated its ability to mitigate this cost with capacity releases through March 31, 2020, and will continue to seek alternatives to reduce exposure to this commitment and potentially enhance the realized value of the natural gas for which it markets.

Litigation Matters

Pending Claims – Ultra Resources Indebtedness Claims

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.

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 Company’s emergence from bankruptcy, pending resolution of make-whole and post-petition interest claims. On April 14, 2017, we funded the account. Following our emergence from bankruptcy, we have 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 post-petition 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 post-petition 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 as of December 31, 2017, and \$175.2 million representing the post-petition interest at the default rate, as described above, which is included in interest expense in the Consolidated Statements of Operations as of December 31, 2017. The Company appealed the court order denying its objections to these claims to the United States Court of Appeals for the Fifth Circuit (the “Appellate Court”).

During 2018 and 2019, the Company entered into settlement agreements (collectively, the “Settlement Agreements”) with holders of certain claims related to Ultra Resources’ prepetition indebtedness (the “Claimants”) pursuant to which the parties agreed to settle the pending disputes between the Claimants and the Company. Under the terms of the various Settlement Agreements, the Claimants have collectively paid approximately \$29.9 million to the Company.

On January 17, 2019, the Appellate Court issued an opinion vacating the order of the Bankruptcy Court denying the Company’s objection to the asserted make-whole and post-petition interest claims and remanding the matter and those determinations to the Bankruptcy Court for further reconsideration. The holders of these claims subsequently filed a petition for rehearing en banc and on November 26, 2019, the Appellate Court, following an en banc review, issued a new opinion that replaced the original opinion from January 17, 2019 (the “En Banc Opinion”). The En Banc Opinion affirmed the primary holding of the Appellate Court’s original opinion and vacated the order of the Bankruptcy Court denying the Company’s objection to the asserted make-whole and post-petition interest claims and remanded the matter and those determinations to the Bankruptcy Court for further reconsideration. As of the date of this filing, the matter is now in the Bankruptcy Court for rehearing. As of December 31, 2019, there is approximately \$240 million of claims outstanding. It is not possible to determine the ultimate disposition of these matters at this time.

Other Claims

We are also party to various disputes with respect to certain overriding royalty and net profits interests in certain of our operated leases in the Pinedale field. At this time, no determination of the outcome of these claims can be made, and we cannot reasonably estimate the potential impact of these claims. We are defending these cases vigorously, and we expect these claims to be resolved in our chapter 11 proceedings. In addition, we are currently involved in various routine disputes and allegations incidental to our business operations. While it is not possible to determine the ultimate disposition of these matters, we believe the Company has adequately reserved for such items where it has been determined that a liability is probable and is reasonably estimable. Additionally, we believe that resolution of all such additional pending or threatened litigation is not likely to have a material adverse effect on our financial position, results of operations, or cash flows.

15. 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, 2019.

A significant counterparty is defined as one that individually accounts for 10% or more of the Company’s total revenues during the year. In 2019, sales to Nevada Power Company and Pacific Gas and Electric accounted for 11.1% and 10.2% of our total revenue, respectively. In 2018 and 2017, the Company had no single customer that represented 10% or more of the Company’s total revenues.

16. 2017 CHAPTER 11 PLAN OF REORGANIZATION:

Voluntary Reorganization Under Chapter 11 and 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.

Plan of Reorganization

Pursuant to the Plan, the significant transactions that occurred upon our emergence from chapter 11 proceedings were as follows:

- On November 21, 2016, we entered into a Plan Support Agreement (as amended, the “PSA”) with certain holders of the Company’s prepetition indebtedness and outstanding common stock as well as a Backstop Commitment Agreement (“BCA”). Pursuant to the BCA, we agreed to conduct a rights offering for new common stock in the Company to be issued upon the effectiveness of the Plan for an aggregate purchase price of \$580.0 million (the “Rights Offering”).
- On February 8, 2017, we entered into a commitment letter with Barclays (as amended, the “Commitment Letter”) pursuant to which, in connection with the consummation of the Plan, Barclays agreed to provide us with secured and unsecured financings in an aggregate amount of up to \$2.4 billion (the “Debt Financings”).
- On the Effective Date, 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 the prepetition senior notes were cancelled and extinguished as provided in the Plan.
- On the Effective Date, the claims of \$450.0 million related to the unsecured 5.75% Senior Notes due 2018 (the “2018 Notes”) and \$850.0 million related to the unsecured 6.125% Senior Notes due 2024 (the “2024 Notes”) were allowed in full, each holder of a claim related to the 2018 Notes and the 2024 Notes received a distribution of common stock in the amount of such holder’s applicable claim, and the Company’s obligations under the 2018 Notes and the 2024 Notes were cancelled and extinguished as provided in the Plan.
- On the Effective Date, we consummated the Rights Offering and the Debt Financings and, as noted above, emerged from bankruptcy.

Fresh Start Accounting

We were 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 post-petition liabilities and allowed claims.

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

During 2017, we incurred significant costs associated with our reorganization and the chapter 11 proceedings. For additional information about the costs of our reorganization and chapter 11 proceedings, see the following table which summarizes the components included in Reorganization items, net in our Consolidated Statements of Operations for the years ended 2017:

	For the Year Ended December 31,
	2017
Professional fees	\$ (66,529)
Gains (losses) (1)	431,107
Make-whole fees	(223,838)
Other (2)	167
Total Reorganization items, net	\$ 140,907

(1) Gains (losses) represent the net gain on the debt to equity exchange related to the Company’s prepetition senior notes.

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

17. SUBSEQUENT EVENTS:

The Company has evaluated the period subsequent to December 31, 2019 for events that did not exist at the balance sheet date but arose after that date and determined that no subsequent events arose in order to keep the financial statements from being misleading, except as otherwise disclosed herein.

18. SUMMARIZED QUARTERLY FINANCIAL INFORMATION (UNAUDITED):

	2019				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total
Operating revenues	\$ 271,461	\$ 155,406	\$ 144,238	\$ 170,927	\$ 742,032
Operating expenses	133,433	137,677	125,819	118,030	514,959
Other income (expense), net:					
Interest expense	(33,327)	(32,376)	(32,372)	(31,323)	(129,398)
Gain (loss) on commodity derivatives	(64,339)	71,654	11,938	(23,850)	(4,597)
Contract settlement	—	—	13,468	—	13,468
Other income (expense), net	285	(43)	60	90	392
Total other (expense) income, net	(97,381)	39,235	(6,906)	(55,083)	(120,135)
Income (loss) before income tax provision (benefit)	40,647	56,964	11,513	(2,186)	106,938
Income tax provision (benefit)	(27)	(141)	—	(882)	(1,050)
Net (loss) income	\$ 40,674	\$ 57,105	\$ 11,513	\$ (1,304)	\$ 107,988
Net income (loss) per common share — basic	\$ 0.21	\$ 0.29	\$ 0.06	\$ (0.01)	\$ 0.55
Net income (loss) per common share — fully diluted	\$ 0.21	\$ 0.29	\$ 0.06	\$ (0.01)	\$ 0.55

	2018				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total
Operating revenues	\$ 225,374	\$ 190,138	\$ 203,776	\$ 273,211	\$ 892,499
Operating expenses	137,686	127,679	126,872	145,506	537,743
Other income (expense), net:					
Interest expense	(35,837)	(37,715)	(38,382)	(36,382)	(148,316)
Gain (loss) on commodity derivatives	(6,530)	(47,271)	(21,804)	(69,607)	(145,212)
Contract settlement, net	—	—	(2,676)	15,332	12,656
Other income, net	2,606	1,981	4,521	2,657	11,765
Total other (expense) income, net	(39,761)	(83,005)	(58,341)	(88,000)	(269,107)
Income (loss) before income tax (benefit) provision	47,927	(20,546)	18,563	39,705	85,649
Income tax provision (benefit)	434	9	—	(1)	442
Net (loss) income	\$ 47,493	\$ (20,555)	\$ 18,563	\$ 39,706	\$ 85,207
Net income (loss) per common share — basic	\$ 0.24	\$ (0.10)	\$ 0.09	\$ 0.20	\$ 0.43
Net income (loss) per common share — fully diluted	\$ 0.24	\$ (0.10)	\$ 0.09	\$ 0.20	\$ 0.43

19. 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:

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. Our Director of Reservoir and Development is primarily responsible for overseeing the preparation of the Company's reserve estimates and has a Bachelor of Science degree in Petroleum Engineering 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, 2019, 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 period ended March 31, 2020 and the years ended December 31, 2019, 2018 and 2017 in this annual report.

The reserves estimates shown herein have been independently evaluated by 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 eight 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 15 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.

Our internal professional staff works closely with 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 NSAI reports are included as Exhibits 99.1 and 99.2 to this annual report.

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, 2019, 2018 and 2017 reflect estimated quantities of proved oil and natural gas reserves for the Company and the changes in total proved reserves as of December 31, 2019, 2018 and 2017. All such reserves were located in the Green River Basin in Wyoming for the year ended December 31, 2019 and 2018, and in the Green River Basin in Wyoming and the Uinta Basin in Utah for the year ended December 31, 2017.

ANALYSES OF CHANGES IN PROVEN RESERVES:

	United States		
	Natural Gas (MMcf)	Oil (MBbls)	NGLs (MBbls)
Reserves, December 31, 2016	2,321,613	21,475	9,903
Extensions, discoveries and additions	50,312	1,117	—
Sales	(89,315)	—	—
Acquisitions	22,400	153	—
Production	(260,009)	(2,775)	—
Revisions	910,991	7,148	(9,832)
Reserves, December 31, 2017	2,955,992	27,118	71
Extensions, discoveries and additions	85,180	1,086	—
Sales	(4,033)	(3,573)	(71)
Production	(260,406)	(2,442)	—
Revisions	145,100	1,256	—
Reserves, December 31, 2018	2,921,833	23,445	—
Extensions, discoveries and additions	13,113	114	—
Production	(230,120)	(1,684)	—
Revisions	(802,226)	(7,248)	—
Reserves, December 31, 2019	1,902,600	14,627	—

	United States		
	Natural Gas (MMcf)	Oil (MBbls)	NGLs (MBbls)
Proved:			
Developed	2,321,613	21,475	9,903
Undeveloped	—	—	—
Total Proved — 2016	2,321,613	21,475	9,903
Developed	2,261,289	21,652	71
Undeveloped	694,703	5,466	—
Total Proved — 2017	2,955,992	27,118	71
Developed	2,243,956	17,876	—
Undeveloped	677,877	5,569	—
Total Proved — 2018	2,921,833	23,445	—
Developed	1,902,600	14,627	—
Undeveloped	—	—	—
Total Proved — 2019	1,902,600	14,627	—

Changes in proved developed reserves: During 2019, substantially all of the changes were attributable to wells drilled in 2019.

Changes in proved undeveloped reserves: The Company's year-end development plans are consistent with SEC guidelines for PUD development within five years. The Company annually reviews all PUDs to ensure an appropriate development plan exists. The changes to the Company's PUD reserves include updates to prior PUD reserves, the transfer and revision of PUD reserves to unproved categories due to development plan changes, and the impact of changes in economic conditions, including commodity prices.

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. Factors such as commodity price, service costs, performance data, and asset mix are subject to change; therefore, 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.

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. Commodity prices have fluctuated 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, 2019, 2018 and 2017 was \$2.44, \$2.59 and \$2.59 per Mcf, respectively, for natural gas, and \$55.36, \$63.49 and \$48.05 per barrel, respectively, for oil and condensate. In 2014, the Company acquired contracts related to NGLs providing an annual election to process NGLs beginning in 2017. In 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 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,		
	2019	2018	2017
Future cash inflows	\$ 5,538,104	\$ 9,195,725	\$ 8,965,949
Future production costs	(2,277,881)	(3,337,779)	(3,587,581)
Future development costs	(355,830)	(1,133,103)	(1,001,024)
Future income taxes	—	(180,057)	—
Future net cash flows	2,904,393	4,544,786	4,377,344
Discount at 10%	(1,193,774)	(2,139,303)	(1,993,016)
Standardized measure of discounted future net cash flows	<u>\$ 1,710,619</u>	<u>\$ 2,405,483</u>	<u>\$ 2,384,328</u>

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.

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

	December 31,		
	2019	2018	2017
Standardized measure, beginning	\$ 2,405,483	\$ 2,384,328	\$ 1,690,946
Net revisions of previous quantity estimates	(713,236)	160,405	840,505
Extensions, discoveries and other changes	16,493	90,609	53,549
Sales of reserves in place	—	(34,768)	(83,887)
Acquisition of reserves	—	—	21,903
Changes in future development costs	106,464	(235,205)	(329,635)
Sales of oil and gas, net of production costs	(486,740)	(593,134)	(589,621)
Net change in prices and production costs	(369,917)	362,084	572,224
Development costs incurred during the period that reduce future development costs	147,042	251,621	8,007
Accretion of discount	243,536	238,433	169,095
Net changes in production rates and other	331,621	(189,017)	31,242
Net change in income taxes	29,873	(29,873)	—
Aggregate changes	<u>(694,864)</u>	<u>21,155</u>	<u>693,382</u>
Standardized measure, ending	<u>\$ 1,710,619</u>	<u>\$ 2,405,483</u>	<u>\$ 2,384,328</u>

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.

COSTS INCURRED IN OIL AND GAS EXPLORATION AND DEVELOPMENT ACTIVITIES:

	Years Ended December 31,		
	2019	2018	2017
United States			
Property Acquisitions:			
Unproved	\$ 817	\$ 1,468	\$ 1,399
Proved	73	1,090	9,147
Exploration*	33,509	156,718	510,710
Development	206,339	266,905	35,934
Total	<u>\$ 240,738</u>	<u>\$ 426,181</u>	<u>\$ 557,190</u>

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

RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES:

	Years Ended December 31,		
	2019	2018	2017
United States			
Oil and gas revenue	\$ 742,032	\$ 892,499	\$ 891,873
Production expenses	(255,292)	(299,365)	(292,095)
Depletion and depreciation	(204,227)	(204,255)	(161,945)
Income tax benefit (expense)	8	(2)	(168,355)
Total	<u>\$ 282,521</u>	<u>\$ 388,877</u>	<u>\$ 269,478</u>

CAPITALIZED COSTS RELATING TO OIL AND GAS PRODUCING ACTIVITIES:

	December 31,	
	2019	2018
Proven Properties:		
Acquisition, equipment, exploration, drilling and environmental costs	\$ 11,820,392	\$ 11,577,281
Less: accumulated depletion, depreciation and amortization	(10,267,973)	(10,079,554)
Total Oil and gas properties, net	<u>\$ 1,552,419</u>	<u>\$ 1,497,727</u>

March 31, 2020 Reserves

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.

In order to fulfill its obligation to evaluate the full cost ceiling and to calculate DD&A of its oil and gas properties, the Company is required to estimate its oil and gas reserves on a quarterly basis. The estimated proven oil and gas reserves considers the estimated future production based on the most current well information available including decline rate changes causing downward revisions and updated pricing in accordance with SEC requirements. The reserve estimated as of March 31, 2020 were prepared by NSAI. The comparable calculated average prices utilized in the preparation of the reserves as of March 31, 2020 were \$2.07 per Mcf and \$55.35 per Bbl. These prices represented a decrease of 15% and <1% for natural gas and oil, respectively, as compared to the pricing utilized as of December 31, 2019.

The unaudited reserve estimates as of March 31, 2020 are as follow:

	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas Equivalents (MMcfe)
Developed	1,694,828	11,902	1,766,239
Undeveloped	—	—	—
Total Proved as of March 31, 2020	1,694,828	11,902	1,766,239

The future net cash flows, before income tax and the discounted future net cash flows before income tax estimated at March 31, 2020 were \$1.907 billion and \$1.218 billion, respectively.

20. 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,		
	2019	2018	2017
General and administrative expense	\$ 1,650	\$ 549	\$ 428
Other income (expense):			
Interest expense	—	—	(71,876)
Income (loss) from unconsolidated affiliates	109,625	85,809	(183,840)
Other expense	13	(44)	90
Reorganization items, net	—	—	433,196
Income before income taxes	107,988	85,216	177,142
Income tax provision (benefit)	—	9	2
Net income	\$ 107,988	\$ 85,207	\$ 177,140

CONDENSED BALANCE SHEET:

	December 31, 2019	December 31, 2018
ASSETS		
Current Assets:		
Cash and cash equivalents	\$ 289	\$ 570
Accounts receivable from related companies	29,939	29,939
Other current assets	—	—
Total current assets	30,228	30,509
Other non-current assets	—	—
Total assets	\$ 30,228	\$ 30,509
LIABILITIES AND SHAREHOLDERS’ EQUITY		
Current liabilities:		
Accrued and other current liabilities	\$ —	\$ —
Total current liabilities	—	0
Advances from unconsolidated affiliates	875,043	1,079,131
Total liabilities	875,043	1,079,131
Total shareholders’ deficit	(844,815)	(1,048,622)
Total liabilities and shareholders’ equity	\$ 30,228	\$ 30,509

CONDENSED STATEMENT OF CASH FLOWS:

	Year Ended December 31,		
	2019	2018	2017
Net cash (used in) operating activities	\$ (281)	\$ (234)	\$ (2,206)
Investing Activities:			
Investment in subsidiaries	(180)	(3,293)	(588,677)
Net cash (used in) provided by investing activities	(180)	(3,293)	(588,677)
Financing activities:			
Shares issued	—	3,294	573,774
Repurchased shares/net share settlements	180	—	14,903
Net cash provided by (used in) financing activities	180	3,294	588,677
(Decrease) increase in cash during the period	(281)	(233)	(2,206)
Cash and cash equivalents, beginning of period	570	803	3,009
Cash and cash equivalents, end of period	<u>\$ 289</u>	<u>\$ 570</u>	<u>\$ 803</u>

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 51 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, 2019 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, 2019, 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.*

None.

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, 2019.

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 116 Inverness Drive East, Suite 400, Englewood, Colorado 80112.

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, 2019.

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, 2019.

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, 2019.

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, 2019.

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

The following documents are filed as part of this report:

1. *Financial Statements:* See Part II, Item 8. “Financial Statements and Supplementary Data.”
2. *Financial Statement Schedules:* Financial statement schedules required under SEC rules but not included in this Form 10-K are omitted because they are not applicable or the required information is contained in the consolidated financial statements or notes thereto.
3. *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	Restated Articles of Incorporation of Ultra Petroleum Corp. (incorporated by reference to Exhibit 3.1 to the Form 10-Q filed by Ultra Petroleum Corp. on August 9, 2019).
3.2	Second Amended and Restated By-Law No. 1 of Ultra Petroleum Corp. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on March 12, 2018).
*4.1	Description of Capital Stock.
4.2	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).
4.3	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).
4.4	First Supplemental Indenture dated as of December 21, 2018, to Indenture dated as of 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 December 26, 2018).
4.5	Indenture dated as of December 21, 2018, among Ultra Resources, Inc., Ultra Petroleum Corp., the subsidiary guarantors party thereto, and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on December 26, 2018).
4.6	First Supplemental Indenture dated as of January 22, 2019, to Indenture dated as of December 21, 2018, among Ultra Petroleum Corp., Ultra Resources, Inc., the subsidiary guarantors party thereto, and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on January 25, 2019).
4.7	Second Supplemental Indenture dated as of January 23, 2019, to Indenture dated as of December 21, 2018, among Ultra Petroleum Corp., Ultra Resources, Inc., 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 January 25, 2019).
4.8	Third Supplemental Indenture dated as of February 4, 2019, to Indenture dated as of December 21, 2018, among Ultra Petroleum Corp., Ultra Resources, Inc., the subsidiary guarantors party thereto, and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.7 to the Annual Report on Form 10-K filed by Ultra Petroleum Corp. on March 7, 2019).
4.9	Fourth Supplemental Indenture dated as of February 13, 2019, to Indenture dated as of December 21, 2018, among Ultra Petroleum Corp., Ultra Resources, Inc., the subsidiary guarantors party thereto, and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.8 to the Annual Report on Form 10-K filed by Ultra Petroleum Corp. on March 7, 2019).

- 4.10 [Fifth Supplemental Indenture dated as of February 15, 2019, to Indenture dated as of December 21, 2018, among Ultra Petroleum Corp., Ultra Resources, Inc., the subsidiary guarantors party thereto, and Wilmington Trust, National Association, as trustee \(incorporated by reference to Exhibit 4.9 to the Annual Report on Form 10-K filed by Ultra Petroleum Corp. on March 7, 2019\).](#)
- 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 [First Amendment to Senior Secured Term Loan Agreement dated as of December 28, 2018, among Ultra Resources Inc., as borrower, Ultra Petroleum Corp. and UP Energy Corporation, as parent guarantor, Barclays Bank PLC, as administrative agent and the lenders and other parties party thereto \(incorporated by reference to Exhibit 10.5 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on December 26, 2018\).](#)
- 10.3 [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. \(incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on April 18, 2017\).](#)
- 10.4 [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 \(incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on June 12, 2017\).](#)
- 10.5 [Second Amendment to Credit Agreement dated as of April 19, 2018, among Ultra Resources, Inc. as borrower, Bank of Montreal, as administrative agent, and each of the lenders and other parties party thereto \(incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on April 20, 2018\).](#)
- 10.6 [Third Amendment to Credit Agreement dated as of December 21, 2018, among Ultra Resources, Inc. as borrower, Bank of Montreal, as administrative agent, and each of the lenders and other parties party thereto \(incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on December 26, 2018\).](#)
- 10.7 [Fourth Amendment to Credit Agreement dated as of February 14, 2019, among Ultra Resources, Inc. as borrower, Bank of Montreal, as administrative agent, and each of the lenders and other parties party thereto \(incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on February 19, 2019\).](#)
- 10.8 [Fifth Amendment to Credit Agreement, dated as of September 16, 2019, by and among Ultra Resources, Inc. as borrower, Bank of Montreal, as administrative agent, and each of the lenders and other parties party thereto \(incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on September 16, 2019\).](#)
- 10.9 [Sixth Amendment to Credit Agreement, dated as of February 14, 2020, by and among Ultra Resources, Inc. as borrower, Bank of Montreal, as administrative agent, and each of the lenders and other parties party thereto \(incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on February 18, 2020\).](#)
- 10.10 [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. \(incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on April 18, 2017\).](#)
- 10.11 [Second Lien Guaranty and Collateral Agreement dated as of December 21, 2018, among Ultra Petroleum Corp. and the other parties signatory thereto, as grantors, and Wilmington Trust, National Association, as collateral agent \(incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on December 26, 2018\).](#)
- 10.12 [First Lien/Second Lien Intercreditor Agreement dated as of December 21, 2018, by and among Bank of Montreal, as revolving administrative agent and as collateral agent for the senior secured parties, Barclays Bank PLC, as term loan administrative agent, Wilmington Trust, National Association, as the second lien collateral agent for the junior priority parties, Ultra Resources Inc., as borrower, and the other grantors party thereto \(incorporated by reference to Exhibit 10.6 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on December 26, 2018\).](#)
- 10.13 [Registration Rights Agreement dated as of April 12, 2017 by and among Ultra Petroleum Corp. and the other parties signatory thereto \(incorporated by reference to Exhibit 10.1 to the Registration Statement on Form 8-A filed by Ultra Petroleum Corp. on April 12, 2017\).](#)

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10.14	<u>Cooperation Agreement dated January 29, 2018 among Ultra Petroleum Corp. and Fir Tree Capital Management LP (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on January 30, 2018).</u>
10.15	<u>Exchange Agreement dated as of October 17, 2018, among Ultra Petroleum Corp., Ultra Resources, Inc., certain subsidiary guarantors thereto and certain noteholders (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on October 17, 2018).</u>
10.16	<u>Exchange Agreement dated as of December 17, 2018, among Ultra Petroleum Corp., Ultra Resources, Inc., certain subsidiary guarantors thereto and certain noteholders (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on December 26, 2018).</u>
10.17	<u>Warrant Agreement dated as of December 21, 2018, among Ultra Petroleum Corp., Computershare Inc. and Computershare Trust Company N.A., as warrant agent (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on December 26, 2018).</u>
10.18	<u>Director Nomination Agreement dated as of December 21, 2018, among Ultra Petroleum Corp. and the holders of 9.00% Cash / 2.00% PIK Senior Secured Second Lien Notes due 2024 of Ultra Resources, Inc. signatory thereto (incorporated by reference to Exhibit 10.7 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on December 26, 2018).</u>
#10.19	<u>Ultra Petroleum Corp. 2017 Stock Incentive Plan, as amended and restated June 8, 2018 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on June 14, 2018).</u>
#10.20	<u>Ultra Petroleum Corp. Annual Incentive Plan (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on July 12, 2018).</u>
#10.21	<u>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).</u>
#10.22	<u>Form of Restricted Stock Unit Agreement (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on June 14, 2018).</u>
#10.23	<u>Form of Restricted Stock Unit Agreement (incorporated by reference to Exhibit 10.4 to the Form 10-Q filed by Ultra Petroleum Corp. on May 9, 2019).</u>
#10.24	<u>Form of Restricted Stock Unit Agreement (incorporated by reference to Exhibit 10.5 to the Form 10-Q filed by Ultra Petroleum Corp. on May 9, 2019).</u>
#10.25	<u>Form of Restricted Stock Unit Grant Agreement (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on July 12, 2018).</u>
#10.26	<u>Form of Restricted Stock Unit Grant Agreement (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q filed by Ultra Petroleum Corp. on November 9, 2018).</u>
#10.27	<u>Employment Agreement of Brad Johnson dated as of March 11, 2019 (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q filed by Ultra Petroleum Corp. on May 9, 2019).</u>
#10.28	<u>Employment Agreement of David W. Honeyfield dated as of November 5, 2018 (incorporated by reference to Exhibit 10.37 to the Annual Report on Form 10-K filed by Ultra Petroleum Corp. on March 7, 2019).</u>
#10.29	<u>Employment Agreement of Jerald J. “Jay” Stratton dated as of May 31, 2018 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on June 1, 2018).</u>
#10.30	<u>Employment Agreement of Jamie Whyte dated as of April 22, 2019 (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q filed by Ultra Petroleum Corp. on August 9, 2019).</u>
#10.31	<u>Employment Agreement of Kason Kerr dated as of April 22, 2019 (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q filed by Ultra Petroleum Corp. on August 9, 2019).</u>
#10.32	<u>Employment Agreement of Maree K. Delgado dated as of August 15, 2018 (incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q filed by Ultra Petroleum Corp. on November 9, 2018).</u>
#10.33	<u>Employment Agreement of Kent Rogers dated as of March 11, 2019 (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q filed by Ultra Petroleum Corp. on May 9, 2019).</u>

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#10.34	<u>Employment Agreement of Mark T. Solomon, dated as of June 17, 2019 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on June 20, 2019).</u>
#*10.35	<u>Ultra Petroleum Corp. Directors Deferred Compensation Plan (incorporated by reference to Exhibit 10.38 to the Annual Report on Form 10-K filed by Ultra Petroleum Corp. on March 7, 2019).</u>
#10.36	<u>Amendment No. 1 to Employment Agreement of Brad Johnson, dated as of March 1, 2020 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on March 12, 2020).</u>
#10.37	<u>Amendment No. 1 to Employment Agreement of David W. Honeyfield, dated as of March 1, 2020 (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on March 12, 2020).</u>
#10.38	<u>Amendment No. 1 to Employment Agreement of Jerald J. Stratton, Jr., dated as of March 1, 2020 (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on March 12, 2020).</u>
#10.39	<u>Amendment No. 1 to Employment Agreement of Kason D. Kerr, dated as of March 1, 2020 (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on March 12, 2020).</u>
#10.40	<u>Amendment No. 1 to Employment Agreement of James N. Whyte, dated as of March 1, 2020 (incorporated by reference to Exhibit 10.5 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on March 12, 2020).</u>
#10.41	<u>Amendment No. 1 to Employment Agreement of Mark T. Solomon, dated as of March 1, 2020 (incorporated by reference to Exhibit 10.6 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on March 12, 2020).</u>
*21.1	<u>List of Subsidiaries of Ultra Petroleum Corp.</u>
*23.1	<u>Consent of Netherland, Sewell & Associates, Inc.</u>
*23.2	<u>Consent of Ernst & Young LLP.</u>
*31.1	<u>Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.</u>
*31.2	<u>Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.</u>
**32.1	<u>Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.</u>
**32.2	<u>Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.</u>
*99.1	<u>Reserve Report Summary prepared by Netherland, Sewell & Associates, Inc. as of December 31, 2019.</u>
*99.2	<u>Reserve Report Summary prepared by Netherland, Sewell & Associates, Inc. as of March 31, 2020.</u>
**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
**	Furnished herewith
#	Management contract or compensatory plan or arrangement required to be filed as an exhibit to this Form 10-K pursuant to Item 15(b).

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/ Brad Johnson
 Name: Brad Johnson
 Title: President and Chief Executive Officer

Date: April 14, 2020

Pursuant to the requirements of the Securities 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.

<i>Signature</i>	<i>Title</i>	<i>Date</i>
<u>/s/ Brad Johnson</u> Brad Johnson	President, Chief Executive Officer and Director (principal executive officer)	April 14, 2020
<u>/s/ David W. Honeyfield</u> David W. Honeyfield	Senior Vice President and Chief Financial Officer (principal financial officer)	April 14, 2020
<u>/s/ Mark T. Solomon</u> Mark T. Solomon	Vice President Controller and Chief Accounting Officer (principal accounting officer)	April 14, 2020
<u>/s/ Evan S. Lederman</u> Evan S. Lederman	Director	April 14, 2020
<u>/s/ Sylvia K. Barnes</u> Sylvia K. Barnes	Director	April 14, 2020
<u>/s/ Neal P. Goldman</u> Neal P. Goldman	Director	April 14, 2020
<u>/s/ Michael J. Keeffe</u> Michael J. Keeffe	Director	April 14, 2020
<u>/s/ Stephen J. McDaniel</u> Stephen J. McDaniel	Director	April 14, 2020
<u>/s/ Alan J. Mintz</u> Alan J. Mintz	Director	April 14, 2020
<u>/s/ Edward A. Scoggins, Jr.</u> Edward A. Scoggins, Jr.	Director	April 14, 2020

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

- **Completion** — Installation of permanent equipment for production of oil or gas, or, in the case of a dry well, to reporting to the appropriate authority that the well has been abandoned.
- **Dry Well** — An exploratory, development, or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.
- **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.
- **Undeveloped acreage** — Acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or gas regardless of whether such acreage contains proved reserves.

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 energy content, 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 more comparative basis 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.
- **Cash costs** — For any period, means the sum of lease operating expenses, liquids gathering system operating lease expense, severance taxes, gathering costs, transportation charges, interest expense and general and administrative expenses divided by production on an Mcfe basis during the period.
- **Cash operating costs** — For any period, means the sum of lease operating expenses, liquids gathering system operating lease expense, severance taxes, gathering costs, transportation charges 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.

DESCRIPTION OF CAPITAL STOCK

The following summary of terms of our common shares, without nominal or par value (the “Common Shares”) and our preferred shares, without nominal or par value (the “Preferred Shares”) is based upon our amended and restated articles of incorporation (as amended by our articles of reorganization, the “Articles”) and our amended and restated bylaws (the “Bylaws”). This summary is not complete and is subject to, and qualified in its entirety by reference to, the Articles and the Bylaws. For a complete description of the terms and provisions of the Common Shares, refer to the Articles, Bylaws and form of common share certificate, which are filed as exhibits to this Annual Report on Form 10-K. Throughout this exhibit, references to the “Company,” “we,” “our,” and “us” refer to Ultra Petroleum Corp. We encourage you to read these documents carefully.

Authorized Capitalization

The Company’s authorized capital consists of an unlimited number of Common Shares and an unlimited number of Preferred Shares.

Common Shares

Voting Rights.

Holders of Common Shares are entitled to receive notice of and to attend all meetings of the shareholders of the Company (the “Shareholder Meeting”) and will have one vote for each Common Share held at all such meetings, except Shareholder Meetings at which only holders of another specified class of shares are entitled to vote separately. Our shareholders do not have the right to cumulate their votes in the election of directors. There are no limitations on the right of non-resident or foreign owners to hold or vote Common Shares imposed by the Yukon Business Corporations Act (the “Business Corporations Act”) or the Articles.

A resolution passed at a Shareholder Meeting by a majority of the votes cast by the shareholders who voted in respect of such a resolution is required to appoint and to remove a director.

Dividends.

Subject to the prior rights of the holders of any series of Preferred Shares that we may issue in the future and any other shares ranking senior to the Common Shares with respect to priority in the payment of dividends, the holders of Common Shares are entitled to receive dividends, as and when declared by our board of directors (the “Board”) out of moneys properly applicable to the payment of dividends, in such amount and in such form as the Board may from time to time determine. Any dividends declared shall be paid in equal amounts per share on all Common Shares outstanding. Our loan documents currently prohibit us from paying dividends on our Common Shares.

Liquidation.

In the event of the dissolution, liquidation or winding-up of our affairs, whether voluntary or involuntary, or any other distribution of our assets among our shareholders for the purpose of winding-up our affairs, subject to the prior rights of the holders of any series of Preferred Shares

that we may issue in the future and any other claims or shares ranking senior to Common Shares with respect to priority in the distribution of assets upon dissolution, liquidation, winding-up or distribution for the purpose of winding-up, the holders of Common Shares are entitled to receive our remaining property and assets of the Company.

Fully Paid.

All of our outstanding Common Shares are fully paid and non-assessable.

Other Rights.

Holders of Common Shares have no redemption or conversion rights, preemptive or other rights to subscribe for our securities and are not entitled to the benefits of any sinking fund.

Preferred Shares

The Board is empowered to (i) authorize the issuance of any amount of Preferred Shares at any time in one or more series and (ii) determine, subject to the limitations in the Articles, the designation, rights, privileges, restrictions and conditions thereof, including the rate or rates, dividend rights, whether cumulative or non-cumulative or partially cumulative, the priorities, purchase for cancellation, retraction or redemption rights, the conversion rights, exchange rights, voting rights and the terms of any share purchase plan or sinking fund with respect thereto.

The issuance of Preferred Shares may have the effect of delaying, deferring or preventing a change in control of the Company without further action by the shareholders and may adversely affect the voting and other rights of the holders of Common Shares. At present, the Company has no plans to issue any Preferred Shares.

Anti-Takeover Provisions

There are provisions of our organizational documents or Yukon law that may hinder or impede take-over bids.

Board of Directors.

The Board shall consist of not less than three and not more than nine directors. Pursuant and subject to the Articles, the directors may, between annual general meetings, appoint one or more additional directors, provided that the number of additional directors does not exceed one third of the number of directors who held office at the expiration of the last annual general meeting and that the total number of directors does not exceed the maximum number of directors fixed under the Articles.

Pursuant to the Articles, at each annual meeting of shareholders, directors will be elected for a term of office to expire on the close of the next succeeding annual meeting of shareholders. As described above in “Common Shares—Voting Rights,” the affirmative vote of a majority of the votes cast by the shareholders at a meeting is required to remove a director.

Preferred Shares.

The Articles authorize the issuance of preferred stock. As described above under “Preferred Shares,” the Board may, without shareholder approval, issue Preferred Shares with rights superior to the rights of the holders of Common Shares that could adversely affect the voting power of the holders of Common Shares.

Yukon Anti-Takeover Statutes.

Under the Business Corporations Act, certain business combinations, including a merger, reorganization or the sale, lease, or other disposition of all or a substantial part of our assets, must be approved by a resolution passed by at least two-thirds of the votes cast by shareholders entitled to vote, and in limited circumstances, by each class or series of shares regardless of whether such shares have the right to vote. In some cases, it may be advantageous for an arrangement (which may include a business combination) to be approved by a Yukon court. Shareholders may also have a right to dissent from certain transactions, in which case, we may be required to pay dissenting shareholders the fair value of their shares provided they have followed the required procedures.

Transfer Agent and Registrar

The transfer agent and registrar for our Common Shares is Computershare Investor Services, Inc.

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

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

Netherland, Sewell & Associates, Inc. has issued reports, as of December 31, 2019, of the “Estimates of Reserves and Future Revenue to the Ultra Petroleum Corp. Interest in Certain Oil and Gas Properties located in Pinedale Field, Sublette County, Wyoming as of December 31, 2019” and as of March 31, 2020, of the “Estimates of Reserves and Future Revenue to the Ultra Petroleum Corp. Interest in Certain Oil and Gas Properties located in Pinedale Field, Sublette County, Wyoming as of March 31, 2020” for Ultra Petroleum Corp. Netherland, Sewell & Associates, Inc. consents to the references in Form 10-K to Netherland, Sewell & Associates, Inc.’s reserves reports dated January 23, 2020, and April 10, 2020, respectively, 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

C.H. (Scott) Rees III, P.E.

Chairman and Chief Executive Officer

Dallas, Texas
April 14, 2020

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 (No. 333-217481) of Ultra Petroleum Corp.;

of our reports dated April 14, 2020, with respect to the consolidated financial statements of Ultra Petroleum Corp. and subsidiaries 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, 2019.

/s/ Ernst & Young LLP

Denver, Colorado

April 14, 2020

CERTIFICATION

I, Brad Johnson, 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/ Brad Johnson

Brad Johnson,
President and Chief Executive Officer
(Principal Executive Officer)

Date: April 14, 2020

CERTIFICATION

I, David W. Honeyfield, 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/ David W. Honeyfield

 David W. Honeyfield,
 Senior Vice President and Chief Financial Officer
 (Principal Financial Officer)

Date: April 14, 2020

**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, 2019, as filed with the Securities and Exchange Commission on the date hereof (the “**Report**”), I, Brad Johnson, 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/ Brad Johnson
Brad Johnson,
President and Chief Executive Officer
(Principal Executive Officer)

Dated: April 14, 2020

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.

**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, 2019, as filed with the Securities and Exchange Commission on the date hereof (the ***“Report”***), I, David W. Honeyfield, Senior Vice President and 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/ David W. Honeyfield
David W. Honeyfield,
*Senior Vice President and Chief Financial
Officer
(Principal Financial Officer)*

Dated: April 14, 2020

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.

January 23, 2020

Mr. Justin Sandifer
Ultra Petroleum Corp.
116 Inverness Drive East, Suite 400
Englewood, Colorado 80112

Dear Mr. Sandifer:

In accordance with your request, we have estimated the proved developed producing reserves and future revenue, as of December 31, 2019, to the Ultra Petroleum Corp. (Ultra) interest in certain gas properties located in Jonah and Pinedale Fields, Sublette County, 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, 2019, to be:

Category	Net Reserves		Future Net Revenue (M\$)	
	Gas (MMCF)	Condensate (MBBL)	Total	Present Worth at 10%
Proved Developed Producing	1,902,600.1	14,626.5	2,904,392.5	1,710,618.3

Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases. Condensate volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. Our study indicates that as of December 31, 2019, there are no proved developed non-producing or proved undeveloped reserves for these properties. As requested, probable or 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.

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 profits 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 2019. For gas volumes, the average Henry Hub spot price of \$2.578 per MMBTU is adjusted for energy content, transportation fees, and market differentials. For condensate volumes, the average West Texas Intermediate spot price of \$55.85 per barrel is adjusted for quality.

transportation fees, and market differentials. The average adjusted product prices weighted by production over the remaining lives of the properties are \$2.442 per MCF of gas and \$55.36 per barrel of condensate.

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. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Ultra and are based on estimated future project cost related to liquid gathering system infrastructure and development. 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. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical field- and lease-level accounting statements.

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 economically producible; 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 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.
Texas Registered Engineering Firm F-2699

/s/ C.H. (Scott) Rees III

By:

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

/s/ Sean A. Martin

By:

Sean A. Martin, P.E. 125354
Petroleum Engineer

By:

/s/ Philip R. Hodgson

Philip R. Hodgson, P.G. 1314
Vice President

Date Signed: January 23, 2020 Date Signed: January 23, 2020

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SAM:CDC

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 2018 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 2018 Petroleum Resources Management System:

Developed Producing Reserves – Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery Reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that 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 that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. 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.

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- (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

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- (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.

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- (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

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- (B) The project has been approved for development by all necessary parties and entities, including governmental entities.
- (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.

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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.

(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.

April 10, 2020

Mr. Justin Sandifer
Ultra Petroleum Corp.
116 Inverness Drive East, Suite 400
Englewood, Colorado 80112

Dear Mr. Sandifer:

In accordance with your request, we have estimated the proved developed producing reserves and future revenue, as of March 31, 2020, to the Ultra Petroleum Corp. (Ultra) interest in certain gas properties located in Jonah and Pinedale Fields, Sublette County, 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 March 31, 2020, to be:

Category	Net Reserves		Future Net Revenue (M\$)	
	Gas (MMCF)	Condensate (MBBL)	Total	Present Worth at 10%
Proved Developed Producing	1,694,827.7	11,901.8	1,907,187.1	1,217,088.5

Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases. Condensate volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. Our study indicates that as of March 31, 2020, there are no proved developed non-producing or proved undeveloped reserves for these properties. As requested, probable or 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.

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 profits 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 April 2019 through March 2020. For gas volumes, the average Henry Hub spot price of \$2.298 per MMBTU is adjusted for energy content, transportation fees, and market differentials. For

condensate volumes, the average West Texas Intermediate spot price of \$55.96 per barrel is adjusted for quality, 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 \$2.074 per MCF of gas and \$55.35 per barrel of condensate.

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. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Ultra and are based on estimated future project cost related to liquid gathering system infrastructure and development. 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. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical field- and lease-level accounting statements.

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 economically producible; 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 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.
Texas Registered Engineering Firm F-2699

/s/ C.H. (Scott) Rees III

By:

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

/s/ Sean A. Martin

By:

Sean A. Martin, P.E. 125354
Petroleum Engineer

By:

/s/ Philip R. Hodgson

Philip R. Hodgson, P.G. 1314
Vice President

Date Signed: April 10, 2020 Date Signed: April 10, 2020

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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 2018 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 2018 Petroleum Resources Management System:

Developed Producing Reserves – Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery Reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that 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 that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. 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.

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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

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Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

- (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.

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- (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

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Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

- (B) The project has been approved for development by all necessary parties and entities, including governmental entities.
- (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.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

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.

(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.