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, 2016

Commission File Number: 001-35467

Halcón Resources Corporation
(Exact name of registrant as specified in its charter)

Delaware	**20-0700684**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

1000 Louisiana Street, Suite 6700, Houston, TX 77002
(Address of principal executive offices)

(832) 538-0300
(Registrant's telephone number)

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

Title of each class	Name of each exchange on which registered
Common Stock, par value $.0001 per share	New York Stock Exchange

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

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

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

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

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

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

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

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

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

As of February 23, 2017, there were 92,986,173 shares outstanding of registrant's $.0001 par value common stock. Based upon the closing price for the registrant's common stock on the New York Stock Exchange as of June 30, 2016, the aggregate market value of shares of common stock held by non-affiliates of the registrant was approximately $37.0 million.

DOCUMENTS INCORPORATED BY REFERENCE

None.

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Special note regarding forward-looking statements

This Annual Report on Form 10-K contains forward-looking statements within the meaning of the federal securities laws. All statements, other than statements of historical facts, concerning, among other things, planned capital expenditures, potential increases in oil and natural gas production, the number and location of wells to be drilled in the future, future cash flows and borrowings, pursuit of potential acquisition or divestiture opportunities, our financial position, business strategy and other plans and objectives for future operations, are forward-looking statements. These forward-looking statements are identified by their use of terms and phrases such as "may," "expect," "estimate," "project," "plan," "objective," "believe," "predict," "intend," "achievable," "anticipate," "will," "continue," "potential," "should," "could" and similar terms and phrases. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. Actual results could differ materially from those anticipated in these forward-looking statements. Readers should consider carefully the risks described under the "Risk Factors" section of this report and other sections of this report which describe factors that could cause our actual results to differ from those anticipated in forward-looking statements, including, but not limited to, the following factors:

- volatility in commodity prices for oil and natural gas, including the current sustained decline in the price for oil;
- our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to fund our operations, satisfy our obligations and fully develop our undeveloped acreage positions;
- our ability to replace our oil and natural gas reserves and production;
- we have historically had substantial indebtedness and may incur more debt in the future;
- higher levels of indebtedness make us more vulnerable to economic downturns and adverse developments in our business;
- the presence or recoverability of estimated oil and natural gas reserves and the actual future production rates and associated costs;
- our ability to successfully develop our large inventory of undeveloped acreage in our resource plays;
- our ability to retain key members of senior management, the board of directors, and key technical employees;
- our ability to successfully integrate acquired oil and natural gas businesses and operations;
- the possibility that acquisitions and divestitures may involve unexpected costs or delays, and that acquisitions may not achieve intended benefits and may divert management's time and energy;
- access to and availability of water and other treatment materials to carry out planned fracture stimulations in our resource plays;
- access to adequate gathering systems, processing facilities, transportation take-away capacity to move our production to market and marketing outlets to sell our production at market prices;
- contractual limitations that affect our management's discretion in managing our business, including covenants that, among other things, limit our ability to incur debt, make investments and pay cash dividends;
- the potential for production decline rates for our wells to be greater than we expect;
- competition, including competition for acreage in resource play holdings;

- environmental risks;
- drilling and operating risks;
- exploration and development risks;
- the possibility that the industry may be subject to future regulatory or legislative actions (including additional taxes and changes in environmental regulations);
- general economic conditions, whether internationally, nationally or in the regional and local market areas in which we do business, may be less favorable than expected, including the possibility that economic conditions in the United States will worsen and that capital markets are disrupted, which could adversely affect demand for oil and natural gas and make it difficult to access capital;
- social unrest, political instability or armed conflict in major oil and natural gas producing regions outside the United States, such as the Middle East, and armed conflict or acts of terrorism or sabotage;
- other economic, competitive, governmental, regulatory, legislative, including federal, state and tribal regulations and laws, geopolitical and technological factors that may negatively impact our business, operations or oil and natural gas prices;
- the insurance coverage maintained by us may not adequately cover all losses that we may sustain;
- title to the properties in which we have an interest may be impaired by title defects;
- senior management's ability to execute our plans to meet our goals;
- the cost and availability of goods and services, such as drilling rigs, fracture stimulation services and tubulars; and
- our dependency on the skill, ability and decisions of third party operators of the oil and natural gas properties in which we have a non-operated working interest.

All forward-looking statements are expressly qualified in their entirety by the cautionary statements in this paragraph and elsewhere in this document. Other than as required under the securities laws, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

Glossary of Oil and Natural Gas Terms

The definitions set forth below apply to the indicated terms as used in this report. All volumes of natural gas referred to herein are stated at the legal pressure base of the state or area where the reserves exist at 60 degrees Fahrenheit and in most instances are rounded to the nearest major multiple.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.

Bcf. One billion cubic feet of natural gas.

Boe. Barrels of oil equivalent in which six Mcf of natural gas equals one Bbl of oil. This ratio does not assume price equivalency and, given price differentials, the price for a barrel of oil equivalent for natural gas may differ significantly from the price for a barrel of oil.

Boe/d. Barrels of oil equivalent per day.

Btu. British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Completion. The installation of permanent equipment for the production of oil or natural gas or, in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Developed property. Property where wells have been drilled and production equipment has been installed.

Development well. A well drilled within the proved areas of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole or well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Extension well. A well drilled to extend the limits of a known reservoir.

Exploratory well. 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 natural gas in another reservoir.

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.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Hydraulic fracturing. The injection of water, sand and chemicals under pressure into rock formations to stimulate oil and natural gas production.

MBbls. One thousand barrels of crude oil or other liquid hydrocarbons.

MBoe. One thousand Boe.

MMBoe. One million Boe.

Mcf. One thousand cubic feet of natural gas.

MMBbls. One million barrels of crude oil or other liquid hydrocarbons.

MMBtu. One million Btu.

MMcf. One million cubic feet of natural gas.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells, as the case may be.

Operator. The individual or company responsible for the exploration, exploitation and production of an oil or natural gas well or lease.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Proved developed producing reserves. Proved developed reserves that are expected to be recovered from completion intervals currently open in existing wells and capable of production.

Proved developed reserves. Proved reserves that are expected to be recovered from existing wellbores, whether or not currently producing, without drilling additional wells. Production of such reserves may require a recompletion.

Proved reserves. Those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for estimation.

Proved undeveloped location. A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

Proved undeveloped reserves. Proved 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.

Recompletion. The completion for production of an existing wellbore in another formation from that in which the well has been previously completed.

Reserve-to-production ratio or Reserve life. A ratio determined by dividing our estimated existing reserves determined as of the stated measurement date by production from such reserves for the prior twelve month period.

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

Spud. Commencement of actual drilling operations.

3-D seismic. The method by which a three dimensional image of the earth's subsurface is created through the interpretation of reflection seismic data collected over a surface grid. 3-D seismic surveys allow for a more detailed understanding of the subsurface than do conventional surveys and contribute significantly to field appraisal, exploitation and production.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

Workover. Operations on a producing well to restore or increase production.

PART I

ITEM 1. BUSINESS

Overview

Unless the context otherwise requires, all references in this report to "Halcón," "our," "us," and "we" refer to Halcón Resources Corporation and its subsidiaries, as a common entity.

Prior year financial statements are not comparable to our current year financial statements due to the adoption of fresh-start accounting. References to "Successor" or "Successor Company" relate to the financial position and results of operations of the reorganized Company subsequent to September 9, 2016. References to "Predecessor" or "Predecessor Company" relate to the financial position and results of operations of the Company prior to, and including, September 9, 2016.

We are an independent energy company focused on the acquisition, production, exploration and development of onshore liquids-rich oil and natural gas assets in the United States. We were incorporated in Delaware on February 5, 2004, recapitalized on February 8, 2012 and reorganized on September 9, 2016. During 2012, we focused our efforts on the acquisition of unevaluated leasehold and producing properties in select prospect areas. In the years since, we have primarily focused on the development of acquired properties and also divested non-core assets in order to fund activities in our core resource plays. Our oil and natural gas assets consist of proved reserves and undeveloped acreage positions in unconventional liquids-rich basins/fields, providing us with an extensive drilling inventory in multiple basins that we believe allow for multiple years of production and broad flexibility to direct our capital resources to projects with the greatest potential returns. As discussed below in more detail under *"Recent Developments,"* we have recently acquired certain properties in the Southern Delaware Basin for $705.0 million and entered into an agreement to sell our assets located in the El Halcón area of East Texas for $500.0 million, which is expected to close by early March 2017.

At December 31, 2016 (Successor), our estimated total proved oil and natural gas reserves, as prepared by our independent reserve engineering firm, Netherland, Sewell & Associates, Inc. (Netherland, Sewell) using Securities and Exchange Commission (SEC) prices of $42.75 per Bbl of oil and $2.481 per MMBtu of natural gas, were approximately 148.6 MMBoe, consisting of 119.6 MMBbls of oil, 15.6 MMBbls of natural gas liquids, and 80.2 Bcf of natural gas. Approximately 58% of our proved reserves were classified as proved developed as of December 31, 2016 (Successor). We maintain operational control of approximately 95% of our proved reserves.

Our total operating revenues for the period of September 10, 2016 through December 31, 2016 (Successor) and the period of January 1, 2016 through September 9, 2016 (Predecessor) were approximately $153.4 million and $266.8 million, respectively, or $420.2 million combined, compared to total operating revenues for 2015 of $550.3 million. The decrease in total operating revenues year over year was driven by the sustained decline in the prices of crude oil and natural gas along with a decrease in our average daily production year over year. During the period of September 10, 2016 through December 31, 2016 (Successor) and the period of January 1, 2016 through September 9, 2016 (Predecessor), production averaged 37,637 Boe/d and 36,787 Boe/d, respectively, or 37,049 Boe/d combined, compared to average daily production of 41,542 Boe/d during 2015 (Predecessor). In response to the sustained decline in commodity prices we reduced our drilling and completion activities in 2016 running only one rig on average in our most economic drilling area. In 2016 (for the combined Successor and Predecessor periods), we participated in the drilling of 90 gross (30.6 net) wells, all of which were completed and capable of production.

Recent Developments

Issuance of 2025 Senior Notes and Repurchase of 2020 Second Lien Notes

On February 16, 2017 (Successor), we issued $850.0 million aggregate principal amount of our new 6.75% senior unsecured notes due 2025 (the 2025 Notes) in a private placement exempt from registration under the Securities Act of 1933, as amended (Securities Act), afforded by Rule 144A and Regulation S, and applicable state securities laws. The 2025 Notes were issued at par and bear interest at a rate of 6.75% per annum, payable semi-annually on February 15 and August 15 of each year, beginning on August 15, 2017. Proceeds from the private placement were approximately $835.1 million after deducting initial purchasers' discounts and commissions and offering expenses. We utilized a portion of the net proceeds from the private placement to fund the repurchase of the outstanding 2020 Second Lien Notes and will use an additional amount of the net proceeds to redeem the remaining amount of such notes, discussed further below, and for general corporate purposes.

On February 9, 2017 (Successor), we commenced a cash tender offer for any and all of our outstanding 2020 Second Lien Notes and on February 15, 2017, we received approximately $289.2 million or 41% of the outstanding aggregate principal amount of the 2020 Second Lien Notes which were validly tendered (and not validly withdrawn). As a result, on February 16, 2017 (Successor), we paid approximately $303.5 million for approximately $289.2 million principal amount of 2020 Second Lien Notes, a make-whole premium of $13.2 million plus accrued and unpaid interest of approximately $1.1 million to purchase such notes pursuant to the tender offer and issued a redemption notice to redeem the remaining 2020 Second Lien Notes. The remaining $410.8 million of 2020 Second Lien Notes will be repurchased through the guaranteed delivery procedures or redeemed at a price of 104.313% of the principal amount thereof, plus accrued and unpaid interest to, but not including, the redemption date. The redemption date is expected to be March 20, 2017.

Pending Divestiture of East Texas Eagle Ford Assets

On January 24, 2017 (Successor), certain of our subsidiaries entered into an Agreement of Sale and Purchase with a subsidiary of Hawkwood Energy, LLC (Hawkwood) for the sale of all of our oil and natural gas properties and related assets located in the Eagle Ford formation of East Texas (the El Halcón Assets) for a total sales price of $500.0 million (the El Halcón Divestiture). The effective date of the proposed sale is January 1, 2017, and we expect to close the transaction in early March 2017. The sale properties include approximately 80,500 net acres prospective for the Eagle Ford formation in East Texas. As of December 31, 2016, estimated proved reserves from these properties were approximately 35.1 MMBoe, or 24% of our estimated year-end 2016 proved reserves. The sale includes approximately 191 gross (135 net) wells that produced approximately 7,600 Boe/d (80% oil) for the year ended December 31, 2016.

The sales price is subject to adjustments for (i) operating expenses, capital expenditures and revenues between the effective date and the closing date, (ii) title, casualty and environmental defects, and (iii) other purchase price adjustments customary in oil and gas purchase and sale agreements. Pursuant to the terms of the agreement, Hawkwood paid into escrow a deposit of $32.5 million at signing, which amount will be applied to the sales price if the transaction closes.

The completion of the El Halcón Divestiture is subject to customary closing conditions. The parties may terminate the sale agreement if certain closing conditions have not been satisfied, if total adjustments to the sales price exceed 20% of the sales price, or $100.0 million, or the transaction has not closed on or before March 20, 2017. If one or more of the closing conditions are not satisfied, or if the transaction is otherwise terminated, the divestiture may not be completed. There can be no assurance that we will sell the El Halcón Assets on the terms or timing described or at all. If the El Halcón Divestiture closes, we intend to use the net proceeds to repay amounts outstanding under our Senior Credit Agreement and for general corporate purposes.

Private Placement of Automatically Convertible Preferred Stock

On January 24, 2017 (Successor), we entered into a stock purchase agreement with certain accredited investors to sell, in a private placement exempt from the registration requirements of the Securities Act pursuant to Section 4(a)(2), approximately 5,518 shares of 8% automatically convertible preferred stock, par value $0.0001 per share, each share of which will be convertible into 10,000 shares of common stock, par value $0.0001 per share (or a proportionate number of shares of common stock with respect to any fractional shares of preferred stock issued), for gross proceeds of approximately $400.1 million, equivalent to a placement at $7.25 per common share. We used the net proceeds from the sale of the preferred stock to partially fund the Pecos County Acquisition.

The preferred stock will convert automatically into common stock on the 20th calendar day after we mail a definitive information statement to holders of our common stock notifying them that holders of a majority of our outstanding common stock consented to the issuance of common stock upon conversion of the preferred stock on January 24, 2017 (Successor). The initial conversion price is subject to adjustment in certain circumstances, including stock splits, stock dividends, rights offerings, or combinations of our common stock. No dividends will be due on the convertible preferred stock if it converts into common stock on or before June 1, 2017. The common stock issuable upon a conversion of the preferred stock represents approximately 37% of our outstanding common stock as of December 31, 2016 on an as-converted basis.

We have agreed to file a registration statement to register the resale of the shares of common stock issuable upon conversion of the preferred stock and to pay penalties in the event such registration is not effective by June 27, 2017.

Acquisition of Southern Delaware Basin Assets (Pecos and Reeves Counties, Texas)

On January 18, 2017 (Successor), we entered into a Purchase and Sale Agreement with Samson Exploration, LLC (Samson), pursuant to which we agreed to acquire a total of 20,901 net acres and related assets in the Southern Delaware Basin located in Pecos and Reeves Counties, Texas (collectively, the Pecos County Assets), for a total purchase price of $705.0 million (the Pecos County Acquisition). The effective date of the acquisition is November 1, 2016, and we closed the transaction on February 28, 2017.

Based on information provided by Samson, we estimate that current net production from the Pecos County Assets is approximately 2,600 Boe/d (72% oil, 15% NGLs, 13% natural gas). We estimate that the Pecos County Assets include a 75% average working interest, with approximately 44% held by production. After closing, we plan to operate two rigs.

The purchase price is subject to adjustments for (i) operating expenses, capital expenditures and revenues between the effective date and the closing date, (ii) title, casualty and environmental defects, and (iii) other purchase price adjustments customary in oil and gas purchase and sale agreements. We funded the Pecos County Acquisition with the net proceeds from the private placement of our preferred stock and borrowings under our Senior Credit Agreement.

Following the agreement with Samson, we have agreed to acquire additional interests in the acreage from a non-operating owner for approximately $22.3 million. This incremental acquisition includes 594 additional net acres and approximately 160 Boe/d of current production and is expected to close in early March 2017.

Option Agreement to Acquire Southern Delaware Basin Assets (Ward County, Texas)

On December 9, 2016 (Successor), we entered into an agreement with a private company, pursuant to which we have acquired the rights to purchase up to 15,040 net acres located in Ward and Winkler Counties, Texas (the Ward County Assets) prospective for the Wolfcamp and Bone Spring formations.

The Ward County Assets are divided into two tracts: the Southern Tract, comprising 6,720 net acres, and the Northern Tract, comprising 8,320 net acres, with separate options for each tract. We paid $5.0 million for the option for the Southern Tract and are currently drilling a commitment well on the Southern Tract. We have until June 15, 2017 to exercise the option on either the Southern Tract acreage or on all 15,040 net acres, in each case for $11,000 per acre. If we initially elect only to exercise our option on the Southern Tract, we would need to pay $5.0 million on or before June 15, 2017 and drill a commitment well on the Northern Tract by September 1, 2017 to earn an option to acquire the Northern Tract acreage for $11,000 per acre by December 31, 2017.

Reorganization

The prices of crude oil and natural gas declined dramatically from mid-year 2014 through 2016, reaching multi-year lows in late 2015 and early 2016, as a result of robust non-Organization of the Petroleum Exporting Countries' (OPEC) supply growth led by unconventional production in the United States, weak demand in emerging markets, and OPEC's decision to sustain high production levels during this period. In response to these developments, among other things, in 2015 and 2016 we reduced our spending and completed a series of transactions that resulted in the reduction of our debt by approximately $1.1 billion and reduced our annual interest burden by approximately $61.5 million. We also extended the maturity date and amended other provisions of certain of our debt agreements.

These efforts proved insufficient in light of continued low commodity prices to ensure our ability to weather the downturn or position us to take advantage of opportunities that might arise. Accordingly, on July 27, 2016, we and certain of our subsidiaries (the Halcón Entities) filed voluntary petitions for relief under chapter 11 of the United States Bankruptcy Code in the U.S. Bankruptcy Court in the District of Delaware (the Bankruptcy Court) to pursue a prepackaged plan of reorganization in accordance with the terms of the Restructuring Support Agreement discussed below. Prior to filing the chapter 11 bankruptcy petitions, on June 9, 2016, the Halcón Entities entered into a restructuring support agreement (the Restructuring Support Agreement) with certain holders of our 13% senior secured third lien notes due 2022 (the Third Lien Noteholders), our 8.875% senior unsecured notes due 2021, 9.25% senior unsecured notes due 2022 and 9.75% senior unsecured notes due 2020 (collectively, the Unsecured Noteholders), the holder of our 8% senior unsecured convertible note due 2020 (the Convertible Noteholder), and certain holders of our 5.75% Series A Convertible Perpetual Preferred Stock (the Preferred Holders), to support a restructuring in accordance with the terms of a plan of reorganization as described therein (the Plan). On September 8, 2016, the Halcón Entities received confirmation of their joint prepackaged plan of reorganization from the Bankruptcy Court and subsequently emerged from chapter 11 bankruptcy on September 9, 2016 (the Effective Date).

Upon emergence, pursuant to the terms of the Plan, the following significant transactions occurred:

- the Predecessor Credit Agreement was refinanced and replaced with the DIP Facility, which was subsequently converted into the Senior Credit Agreement;
- the Second Lien Notes (consisting of $700.0 million in aggregate principal amount outstanding of 8.625% senior secured notes due 2020 and $112.8 million in aggregate principal amount outstanding of 12% senior secured notes due 2022) were unimpaired and reinstated;
- the Third Lien Notes were cancelled and the Third Lien Noteholders received their pro rata share of 76.5% of the common stock of reorganized Halcón, together with a cash payment of $33.8 million, and accrued and unpaid interest on their notes through May 15, 2016, which was paid prior to the chapter 11 bankruptcy filing, in full and final satisfaction of their claims;

- the Unsecured Notes were cancelled and the Unsecured Noteholders received their pro rata share of 15.5% of the common stock of reorganized Halcón, together with a cash payment of $37.6 million and warrants to purchase 4% of the common stock of reorganized Halcón (with a four year term and an exercise price of $14.04 per share), and accrued and unpaid interest on their notes through May 15, 2016, which was paid prior to the chapter 11 bankruptcy filing, in full and final satisfaction of their claims;
- the Convertible Note was cancelled and the Convertible Noteholder received 4% of the common stock of reorganized Halcón, together with a cash payment of $15.0 million and warrants to purchase 1% of the common stock of reorganized Halcón (with a four year term and an exercise price of $14.04 per share), in full and final satisfaction of their claims;
- the general unsecured claims were unimpaired and paid in full in the ordinary course;
- all outstanding shares of the preferred stock were cancelled and the Preferred Holders received their pro rata share of $11.1 million in cash, in full and final satisfaction of their interests; and
- all of the outstanding shares of common stock were cancelled and the common stockholders received their pro rata share of 4% of the common stock of reorganized Halcón, in full and final satisfaction of their interests.

Each of the foregoing percentages of equity in the reorganized company were as of September 9, 2016 and subject to dilution from the exercise of the new warrants described above, a management incentive plan and other future issuances of equity securities.

Fresh-start Accounting

Upon our emergence from chapter 11 bankruptcy, on September 9, 2016, we adopted fresh-start accounting in accordance with the provisions set forth in Accounting Standards Codification (ASC) 852, *Reorganizations,* as (i) the Reorganization Value of our assets immediately prior to the date of confirmation was less than the post-petition liabilities and allowed claims and (ii) the holders of our existing voting shares of the Predecessor entity received less than 50% of the voting shares of the emerging entity.

Adopting fresh-start accounting results in a new financial reporting entity with no beginning or ending retained earnings or deficit balances as of the fresh-start reporting date. Upon the adoption of fresh-start accounting, our assets and liabilities were recorded at their fair values as of the fresh-start reporting date. Our adoption of fresh-start accounting may materially affect our results of operations following the fresh-start reporting date, as we have a new basis in our assets and liabilities. As a result of the adoption of fresh-start reporting and the effects of the implementation of the Plan, our consolidated financial statements subsequent to September 9, 2016 are not comparable to our consolidated financial statements prior to September 9, 2016. References to "Successor" or "Successor Company" relate to the financial position and results of operations of the reorganized Company subsequent to September 9, 2016. References to "Predecessor" or "Predecessor Company" related to the financial position and results of operations of the Company prior to, and including, September 9, 2016, as such, "black-line" financial statements are presented to distinguish between the Predecessor and Successor companies. Refer to Item 8. *Consolidated Financial Statements and Supplementary Data—Note 3, "Fresh-start Accounting,"* for further details.

HK TMS Divestiture

On September 30, 2016 (Successor), certain of our wholly-owned subsidiaries executed an Assignment and Assumption Agreement with an affiliate of Apollo Global Management (Apollo) pursuant to which Apollo acquired one hundred percent (100%) of the common shares (the Membership Interests) of HK TMS, LLC (HK TMS), which the transaction is referred to as the HK

TMS Divestiture. HK TMS was previously a wholly-owned subsidiary of ours and held all of our oil and natural gas properties in the Tuscaloosa Marine Shale. In exchange for the assignment of the Membership Interests, Apollo assumed all obligations relating to the Membership Interests, which were previously classified as *"Mezzanine Equity"* on the consolidated balance sheets of HK TMS, from and after such date. The Tuscaloosa Marine Shale properties generated net production of approximately 530 Boe/d during the nine months ended September 30, 2016 and had 1.1 MMBoe of proved reserves at December 31, 2015 (Predecessor).

Successor Senior Revolving Credit Facility

On the Effective Date, we entered into a senior secured revolving credit agreement (the Senior Credit Agreement) with JPMorgan Chase Bank, N.A., as administrative agent, and certain other financial institutions party thereto, as lenders, which refinanced the DIP Facility, discussed below. The Senior Credit Agreement provides for a $1.5 billion senior secured reserve-based revolving credit facility with a current borrowing base of $600.0 million. The maturity date of the Senior Credit Agreement is the earlier of (i) July 28, 2021 and (ii) the 120th day prior to the February 1, 2020 stated maturity date of our 2020 Second Lien Notes (defined below), if such notes have not been refinanced, redeemed or repaid in full on or prior to such 120th day. The first borrowing base redetermination will be on May 1, 2017 and redeterminations will occur semi-annually thereafter, with us and the lenders each having the right to one interim unscheduled redetermination between any two consecutive semi-annual redeterminations. The borrowing base takes into account the estimated value of our oil and natural gas properties, proved reserves, total indebtedness, and other relevant factors consistent with customary oil and natural gas lending criteria. Amounts outstanding under the Senior Credit Agreement bear interest at specified margins over the base rate of 1.75% to 2.75% for ABR-based loans or at specified margins over LIBOR of 2.75% to 3.75% for Eurodollar-based loans. These margins fluctuate based on our utilization of the facility. We may elect, at our option, to prepay any borrowings outstanding under the Senior Credit Agreement without premium or penalty (except with respect to any break funding payments which may be payable pursuant to the terms of the Senior Credit Agreement). Additionally, if we have outstanding borrowings or letters of credit or reimbursement obligations in respect of letters of credit and the Consolidated Cash Balance (as defined in the Senior Credit Agreement) exceeds $100.0 million as of the close of business on the most recently ended business day, we may also be required to make mandatory prepayments.

The Senior Credit Agreement also contains certain financial covenants, including the maintenance of (i) a Total Net Indebtedness Leverage Ratio (as defined in the Senior Credit Agreement) not to exceed 4.75:1.00 initially, determined as of each four fiscal quarter period and commencing with the fiscal quarter ending September 30, 2016, stepping down to 4.50:1.00 and 4.00:1.00 on September 30, 2017 and March 31, 2019, respectively, and (ii) a Current Ratio (as defined in the Senior Credit Agreement) not to be less than 1.00:1.00, commencing with the fiscal quarter ending December 31, 2016.

DIP Facility

In connection with the chapter 11 bankruptcy proceedings, we entered into a commitment letter pursuant to which the lenders party thereto committed to provide, subject to certain conditions, a $600.0 million debtor-in-possession senior secured, super-priority revolving credit facility (the DIP Facility) and to replace it upon emergence with a $600.0 million senior secured reserve-based revolving credit facility, discussed above. Proceeds from the DIP Facility were used to refinance borrowings under our Predecessor Credit Agreement. Availability under the DIP Facility was $500.0 million upon interim approval by the Bankruptcy Court, and rose to $600.0 million upon entry of a final order. The DIP Facility was refinanced by the Senior Credit Agreement on the Effective Date. Loans under the DIP Facility bore interest at specified margins over the base rate of 1.75% to 2.75% for ABR-based loans or at specified margins over LIBOR of 2.75% to 3.75% for Eurodollar-based loans. These margins fluctuated based on the utilization of the DIP Facility.

2017 Capital Budget

We expect to spend approximately $300 million on drilling and completion capital expenditures during 2017. In addition, we expect to spend approximately $15 million on infrastructure, seismic and other in 2017. Approximately 65% of our 2017 drilling and completion budget is expected to be spent in the Bakken/Three Forks formations in North Dakota and approximately 35% is budgeted for the Southern Delaware Basin. Our 2017 drilling and completion budget currently contemplates running two to three operated rigs during the year, is based on our current view of market conditions and current business plans, and is subject to change.

We expect to fund our budgeted 2017 capital expenditures with cash flows from operations and, to a lesser extent, with borrowings under our Senior Credit Agreement. We strive to maintain financial flexibility and may access capital markets as necessary to maintain substantial borrowing capacity under our Senior Credit Agreement, facilitate drilling on our large undeveloped acreage position and permit us to selectively expand our acreage position. In the event our cash flows are materially less than anticipated and other sources of capital we historically have utilized are not available on acceptable terms, we may further curtail our capital spending.

Our financial results depend upon many factors, but are largely driven by the volume of our oil and natural gas production and the price that we receive for that production. Our production volumes will decline as reserves are depleted unless we expend capital in successful development and exploration activities or acquire properties with existing production. The amount we realize for our production depends predominately upon commodity prices and our related commodity price hedging activities, which are affected by changes in market demand and supply, as impacted by overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. Accordingly, finding and developing oil and natural gas reserves in an economical manner is critical to our long-term success.

Business Strategy

Our primary long-term objective is to increase stockholder value by growing reserves, production and cash flow. To accomplish this objective, we intend to execute the following business strategies:

- ***Develop and Grow Our Liquids Rich Resource-Style Acreage Positions Using Our Proven Development Expertise.*** We plan to continue to acquire high quality assets in liquids-rich resource plays to improve our asset quality and expand our drilling inventory. We plan to leverage our management team's expertise and the latest available technologies to economically develop our existing property portfolio in addition to any assets we may acquire. We are the operator for the majority of our acreage, which gives us control over the timing of capital expenditures, execution and costs. It also allows us to adjust our capital spending based on drilling results and the economic environment. Our leasing strategy is to pursue long-term contracts that allow us to maintain flexible development plans and avoid short-term obligations to drill wells, as have been common in other resource plays. As operator, we are also able to evaluate industry drilling results and implement improved operating practices which may enhance our initial production rates, ultimate recovery factors and rate of return on invested capital.

- ***Manage Our Property Portfolio Actively.*** We continually evaluate our property base to identify and divest non-core assets and higher cost or lower volume producing properties with limited development potential, which allows us to focus on a portfolio of core properties with the greatest economic potential to increase our proved reserves and production.

- ***Maintain Strong Balance Sheet and Financial Flexibility.*** We believe our cash, internally generated cash flows, borrowing capacity, non-core asset sales and access to capital markets will provide us with sufficient liquidity to execute our current capital program and strategy. We have no near term debt maturities. Our management team is focused on maintaining a strong balance sheet. We also employ a hedging program to reduce the variability of our cash flows used to support our capital spending.

Our Competitive Strengths

We have a number of competitive strengths that we believe will allow us to successfully execute our business strategies:

- ***Proven Management Team.*** Our management team and technical professionals, including geologists and engineers, have decades of combined experience in the industry and a track record for creating shareholder value.
- ***Premier Asset Base.*** Our proved reserves, production and acreage are located in concentrated positions in two premier onshore U.S. basins. These basins provide exposure to a variety of reservoir formations, each of which has its own characteristics that impact the costs to drill, complete and operate as well as the composition (and therefore value) of the hydrocarbon stream. We believe that this geographic diversity provides us with broad flexibility to direct our capital resources to projects with the greatest potential returns and access to multiple key end markets, which mitigates our exposure to temporary price dislocations in any one market.
- ***Extensive Experience in Resource Plays.*** Our team has significant experience in all aspects of the development of resource plays. We have been successful in consistently improving drilling times and reserve recoveries through innovation, the use of new technologies and a focus on controlling costs. In addition to our core strength in exploration and production, our personnel have experience in building midstream infrastructure and have managed oilfield service activities.
- ***Strong Technical Team.*** We believe that there are certain competitive advantages to be gained by employing a highly skilled technical staff. Our technical team has significant experience and expertise in applying the most sophisticated technologies used in conventional and unconventional resource style plays, including 3-D seismic interpretation, horizontal drilling, deep onshore drilling, comprehensive multi-stage hydraulic fracture stimulation programs, and other exploration, production, and processing technologies. We believe this technical expertise is partly responsible for our management team's strong track record of successful exploration and development, including new discoveries and defining core producing areas in emerging plays.

Oil and Natural Gas Reserves

The proved reserves estimates shown herein for the years ended December 31, 2016 (Successor), 2015 and 2014 (Predecessor) have been independently evaluated by Netherland, Sewell, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. Netherland, Sewell was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within Netherland, Sewell, the technical persons primarily responsible for preparing the estimates set forth in the Netherland, Sewell reserves report incorporated herein are Mr. J. Carter Henson, Jr. and Mr. Mike K. Norton. Mr. Henson, a Licensed Professional Engineer in the State of Texas (No. 73964), has been practicing consulting petroleum engineering at Netherland, Sewell since 1989 and has over 8 years of prior industry experience. He graduated from Rice University in 1981 with a Bachelor of Science Degree in Mechanical Engineering. Mr. Norton, a Licensed Professional Geoscientist in the State of Texas (No. 441), has been a practicing petroleum geoscience consultant at Netherland, Sewell since 1989 and has over ten years of prior industry experience. He graduated from Texas A&M University in 1978 with a Bachelor of Science Degree in Geology. Netherland, Sewell has reported to us that 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 board of directors has established a reserves committee composed of three independent directors, all of whom have experience in energy company reserve evaluations. Our independent engineering firm reports jointly to the reserves committee and to our Senior Vice President of Corporate Reserves. The reserves committee is charged with ensuring the integrity of the process of selection and engagement of the independent engineering firm and in making a recommendation to our board of directors as to whether to approve the report prepared by our independent engineering firm. Ms. Tina Obut, our Senior Vice President of Corporate Reserves, is primarily responsible for overseeing the preparation of the annual reserve report by Netherland, Sewell. She graduated from Marietta College with a Bachelor of Science degree in Petroleum Engineering, received a Master of Science degree in Petroleum and Natural Gas Engineering from Penn State University and a Master of Business Administration degree from the University of Houston.

The reserves information in this Annual Report on Form 10-K represents only estimates. There are a number of uncertainties inherent in estimating quantities of proved reserves, including many factors beyond our control. Reserve evaluation is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. 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 may vary significantly. In addition, results of drilling, testing and production subsequent to the date of an estimate may lead to revising the original estimate. Accordingly, initial reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. The meaningfulness of such estimates depends primarily on the accuracy of the assumptions upon which they were based. Except to the extent we acquire additional properties containing proved reserves or conduct successful exploration and development activities or both, our proved reserves will decline as reserves are produced. For additional information regarding estimates of proved reserves, the preparation of such estimates by Netherland, Sewell and other information about our oil and natural gas reserves, see Item 8. *Consolidated Financial Statements and Supplementary Data*—"*Supplemental Oil and Gas Information (Unaudited)*."

Proved reserve estimates are based on the unweighted arithmetic average prices on the first day of each month for the 12-month period ended December 31, 2016 (Successor). Average prices for the 12-month period were as follows: West Texas Intermediate (WTI) crude oil spot price of $42.75 per Bbl, adjusted by lease or field for quality, transportation fees, and market differentials and a Henry Hub natural gas spot price of $2.481 per MMBtu, as adjusted by lease or field for energy content, transportation fees, and market differentials. All prices and costs associated with operating wells were held constant in accordance with SEC guidelines.

The following table presents certain proved reserve information as of December 31, 2016 (Successor).

Proved Reserves (MBoe)*(1)*	
Developed	85,908
Undeveloped	62,706
Total	148,614

(1) Natural gas reserves are converted to oil reserves using a ratio of six Mcf to one Bbl of oil. This ratio does not assume price equivalency and, given price differentials, the price for a barrel of oil equivalent for natural gas may differ significantly from the price for a barrel of oil.

The following table sets forth the number of productive oil and natural gas wells in which we owned an interest as of December 31, 2016 (Successor) and 2015 (Predecessor). Shut-in wells currently not capable of production are excluded from the well information below.

	Years Ended December 31,			
	2016		2015	
	Gross	Net	Gross	Net
Oil	1,470	356.9	1,384	326.5
Natural Gas	71	36.8	74	42.6
Total	1,541	393.7	1,458	369.1

Oil and Natural Gas Production

Core Resource Plays

In general, our core resource plays are characterized by high oil and liquids-rich natural gas content in thick, continuous sections of source rock that can provide repeatable drilling opportunities and significant initial production rates. Our core resource plays are as follows:

Bakken/Three Forks Formations

We have working interests in approximately 116,000 net acres as of December 31, 2016 (Successor) prospective in the Bakken/Three Forks formations in North Dakota. Multiple initiatives are underway to lower costs and improve recoveries in our operated project areas. We expect to spud 45 to 50 gross horizontal wells on our operated acreage in 2017 with an average working interest of 72%. In 2017, we expect to operate on average two rigs in the Williston Basin. As of December 31, 2016 (Successor), we had approximately 300 operated wells producing in this area in addition to minor working interests in hundreds of non-operated wells. Our average daily net production from this area for the year ended December 31, 2016 (Successor) was approximately 27,600 Boe/d. As of December 31, 2016 (Successor), estimated proved reserves for the Bakken/Three Forks formations were approximately 112.3 MMBoe, of which approximately 64% were classified as proved developed and approximately 36% as proved undeveloped.

Delaware Basin

On February 28, 2017, we acquired 20,901 net acres in the Southern Delaware Basin in Pecos and Reeves Counties, Texas and we also have the option to acquire up to 15,040 net acres in Ward and Winkler Counties, Texas. If we exercise the options in full, we will have working interests in 35,941 net acres prospective for the Wolfcamp, Bone Spring and other formations in West Texas.

Based on information provided by Samson, we estimate that current net production from the Pecos County Assets is approximately 2,600 Boe/d. We estimate that the Pecos County Assets include a 75% average working interest, with approximately 44% held by production.

Non-core Areas

East Texas Eagle Ford Formation (El Halcón)

We have working interests in approximately 80,500 net acres as of December 31, 2016 (Successor) prospective for the Eagle Ford formation in Brazos, Burleson, and Robertson Counties, Texas, with targeted depths ranging from 7,000 feet to 10,000 feet. We finished 2016 with no operated rigs and approximately 191 gross (135 net) producing wells in this area. As of December 31, 2016 (Successor), estimated proved reserves for the El Halcón area were approximately 35.1 MMBoe, of which approximately 36% were classified as proved developed and approximately 64% as proved undeveloped. Our average daily net production from this area for the year ended December 31, 2016 (Successor) was approximately 7,600 Boe/d. On January 24, 2017 (Successor), we entered into an Agreement of Sale and Purchase with a subsidiary of Hawkwood Energy, LLC for the sale of the El Halcón Assets for a total sales price of $500.0 million. The transaction is expected to close in early March 2017.

Other Non-core Areas

We have other oil and natural gas properties with varying working interests located in the Utica/Point Pleasant formations in Ohio and Pennsylvania and the Austin Chalk Trend in East Texas. Production from these other non-core areas totaled approximately 1,500 Boe/d for the year ended December 31, 2016 (Successor). As of December 31, 2016 (Successor), estimated proved reserves for these properties were approximately 1.2 MMBoe in aggregate, of which all were classified as proved developed. We may consider divesting certain of these assets over time.

Liquids-Rich Exploratory Plays

In addition to the disclosed areas, we may acquire acreage in other unconventional exploratory plays as opportunities arise. Our strategy for our exploratory projects is to use our in-house geologic and engineering expertise to identify underdeveloped areas that we believe are prospective for oil or liquids-rich production. We can provide no assurance that any of these exploratory areas, or any wells we subsequently drill in the formations we have targeted for exploration and development, will be successful.

Risk Management

We have designed a risk management policy for the use of derivative instruments to provide partial protection against certain risks relating to our ongoing business operations, such as commodity price declines. Derivative contracts are utilized to hedge our exposure to price fluctuations and reduce the variability in our cash flows associated with anticipated sales on future oil and natural gas production. Our objective generally is to hedge 70-80% of our anticipated oil and natural gas production for the next 18 to 24 months. However, our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. Our hedge policies and objectives change as our operational profile changes and/or commodity prices. Our future performance is subject to commodity price risks and our future cash flows from operations may be subject to greater volatility than historically. We do not enter into derivative contracts for speculative trading purposes.

While there are many different types of derivatives available, we typically use costless collar agreements, swap agreements and deferred put options to attempt to manage price risk more effectively. The costless collar agreements are put and call options used to establish floor and ceiling commodity prices for a fixed volume of production during a certain time period. All costless collar agreements provide for payments to counterparties if the index price exceeds the ceiling and payments from the counterparties if the index price is below the floor. The swap agreements call for payments to, or receipts from, counterparties depending on whether the index price of oil or natural gas for the period is greater or less than the fixed price established for the period contracted under the swap agreement. Under deferred put option agreements, we pay a fixed premium to lock in a specified floor price for a specified future period. If the index price of oil or natural gas falls below the contracted floor price, the counterparty pays us the difference between the index price and the floor price (netted against the fixed premium payable to the counterparty). If the index price rises above floor price, we pay the fixed premium.

It is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. We did not post collateral under any of our derivative contracts as they are secured under our Senior Credit Agreement or are uncollateralized trades. We will continue to evaluate the benefit of employing derivatives in the future. See Item 7A. *Quantitative and Qualitative Disclosures about Market Risk* and Item 8. *Consolidated Financial Statements and Supplementary Data*—Note 9*, "Derivative and Hedging Activities,"* for additional information.

Oil and Natural Gas Operations

Our principal properties consist of leasehold interests in developed and undeveloped oil and natural gas properties and the reserves associated with these properties. Generally, oil and natural gas leases remain in force as long as production in paying quantities is maintained. Leases on undeveloped oil and natural gas properties are typically for a primary term of three to five years within which we are generally required to develop the property or the lease will expire. In some cases, the primary term of leases on our undeveloped properties can be extended by option payments; the amount of any payments and time extended vary by lease.

The table below sets forth the results of our drilling activities for the periods indicated:

	Years Ended December 31,					
	2016		2015		2014	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive(1)	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total Exploratory	—	—	—	—	—	—
Extension Wells:						
Productive(1)	54	8.5	72	18.1	207	51.1
Dry	—	—	—	—	—	—
Total Extension	54	8.5	72	18.1	207	51.1
Development Wells:						
Productive(1)	36	22.1	112	30.9	113	47.2
Dry	—	—	—	—	—	—
Total Development	36	22.1	112	30.9	113	47.2
Total Wells:						
Productive(1)	90	30.6	184	49.0	320	98.3
Dry	—	—	—	—	—	—
Total	90	30.6	184	49.0	320	98.3

(1) *Although a well may be classified as productive upon completion, future changes in oil and natural gas prices, operating costs and production may result in the well becoming uneconomical, particularly extension or exploratory wells where there is no production history.*

We own interests in developed and undeveloped oil and natural gas acreage in the locations set forth in the table below. These ownership interests generally take the form of working interests in oil and natural gas leases that have varying provisions. The following table presents a summary of our acreage interests as of December 31, 2016:

State	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Montana	7,352	1,616	4,073	1,644	11,425	3,260
North Dakota	261,028	107,827	42,342	8,256	303,370	116,083
Ohio	3,134	3,122	37,059	35,943	40,193	39,065
Oklahoma	—	—	27,694	15,002	27,694	15,002
Pennsylvania	917	852	74,758	72,746	75,675	73,598
Texas	285,436	173,039	54,874	36,926	340,310	209,965
Total Acreage	557,867	286,456	240,800	170,517	798,667	456,973

The table below reflects the percentage of our total net undeveloped and mineral acreage as of December 31, 2016 that will expire each year if we do not establish production in paying quantities on the units in which such acreage is included or do not pay (to the extent we have the contractual right to pay) delay rentals or obtain other extensions to maintain the lease.

Year	Percentage Expiration
2017	25%
2018	15%
2019	4%
2020	1%
2021 & beyond	55%
	100%

For our proved undeveloped locations that are not scheduled to be drilled until after lease expiration, we continually review our near-term lease expirations, actively pursue lease extensions and renewals and modify our drilling schedules in order to preserve the leases.

At December 31, 2016 (Successor), we had estimated proved reserves of approximately 148.6 MMBoe comprised of 119.6 MMBbls of crude oil, 15.6 MMBbls of natural gas liquids, and 80.2 Bcf of natural gas. The following table sets forth, at December 31, 2016 (Successor), these reserves:

	Proved Developed	Proved Undeveloped	Total Proved
Oil (MBbls)	67,983	51,617	119,600
Natural Gas Liquids (MBbls)	9,337	6,304	15,641
Natural Gas (MMcf)	51,525	28,713	80,238
Equivalent (MBoe)[(1)]	85,908	62,706	148,614

(1) Natural gas reserves are converted to oil reserves using a ratio of six Mcf to one Bbl of oil. This ratio does not assume price equivalency and, given price differentials, the price for a barrel of oil equivalent for natural gas may differ significantly from the price for a barrel of oil.

At December 31, 2016 (Successor), our estimated proved undeveloped (PUD) reserves were approximately 62.7 MMBoe, a 2.2 MMBoe net decrease over the previous year's estimate of 64.9 MMBoe. The following table details the changes in PUD reserves for 2016 (in MBoe):

Beginning proved undeveloped reserves at December 31, 2015 (Predecessor)	64,919
Undeveloped reserves transferred to developed	(7,510)
Revisions	(9,314)
Purchases	526
Divestitures	(246)
Extension and discoveries	14,331
Ending proved undeveloped reserves at December 31, 2016 (Successor)	62,706

The decrease in PUD reserves was due to a negative revision associated with the decline in the unweighted 12-month average prices of oil and natural gas during 2016. Negative revisions of approximately 9 MMBoe were largely associated with PUD locations in the Bakken/Three Forks and El Halcón areas that became uneconomic at the lower unweighted 12-month average prices of oil and natural gas as of December 31, 2016 (Successor), or were removed because they no longer met the SEC five year development requirement as we have reduced our capital spending since the prior year as a result of the sustained decline in oil and natural gas prices. Further reductions of approximately 8 MMBoe in PUD reserves were the direct result of development through our drilling program and the associated transfer of those reserves to proved developed reserves, primarily in the Bakken/Three Forks and El Halcón areas.

As of December 31, 2016 (Successor), all of our PUD reserves are planned to be developed within five years from the date they were initially recorded. During 2016, approximately $181.7 million in capital expenditures went toward the development of proved undeveloped reserves, which includes drilling, completion and other facility costs associated with developing proved undeveloped wells.

Reliable technologies were used to determine areas where PUD locations are more than one offset location away from a producing well. These technologies include seismic data, wire line open hole log data, core data, log cross-sections, performance data, and statistical analysis. In such areas, these data demonstrated consistent, continuous reservoir characteristics in addition to significant quantities of economic estimated ultimate recoveries from individual producing wells. Our management team has been a leader in data gathering and evaluation in these areas and was instrumental in developing consortiums that allow various operators to exchange data. We relied only on production flow tests and historical production data, along with the reliable geologic data mentioned above to estimate proved reserves. No other alternative methods or technologies were used to estimate proved reserves.

The estimates of quantities of proved reserves contained in this report were made in accordance with the definitions contained in SEC Release No. 33-8995, *Modernization of Oil and Gas Reporting*. For additional information on our oil and natural gas reserves, see Item 8. *Consolidated Financial Statements and Supplementary Data—"Supplemental Oil and Gas Information (Unaudited)."*

We account for our oil and natural gas producing activities using the full cost method of accounting in accordance with SEC regulations. Accordingly, all costs incurred in the acquisition, exploration, and development of proved and unproved oil and natural gas properties, including the costs of abandoned properties, dry holes, geophysical costs, direct internal costs and annual lease rentals are capitalized. All general and administrative corporate costs unrelated to drilling activities are expensed as incurred. Sales or other dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to proved reserves would significantly change. Depletion of evaluated oil and natural gas properties is computed on the units of production method based on proved reserves. The net capitalized costs of evaluated oil and natural gas properties are subject to a quarterly full cost ceiling test. Our net book value of oil and natural gas properties at March 31, June 30, and September 30, 2016 exceeded the respective ceiling amounts for each quarter end. As a result, we recorded full cost ceiling test impairments before income taxes of $754.8 million and $420.9 million for the period from January 1, 2016 through September 9, 2016 (Predecessor), and the period from September 10, 2016 through December 31, 2016 (Successor), respectively. See further discussion in Item 8. *Consolidated Financial Statements and Supplementary Data*—Note 6, *"Oil and Natural Gas Properties."*

Capitalized costs of our evaluated and unevaluated properties at December 31, 2016 (Successor), 2015 and 2014 (Predecessor) are summarized as follows (in thousands):

	Successor	Predecessor	
	December 31, 2016	December 31, 2015	December 31, 2014
Oil and natural gas properties (full cost method):			
Evaluated	$1,269,034	$ 7,060,721	$ 6,390,820
Unevaluated	316,439	1,641,356	1,829,786
Gross oil and natural gas properties	1,585,473	8,702,077	8,220,606
Less—accumulated depletion	(465,849)	(5,933,688)	(2,953,038)
Net oil and natural gas properties	$1,119,624	$ 2,768,389	$ 5,267,568

The following table summarizes our oil, natural gas and natural gas liquids production volumes, average sales price per unit and average costs per unit. In addition, this table summarizes our production for each field that contains 15% or more of our total proved reserves:

	Successor	Predecessor		
	Period from September 10, 2016 through December 31, 2016	Period from January 1, 2016 through September 9, 2016	Years Ended December 31, 2015	Years Ended December 31, 2014
Production:				
Crude oil—MBbl				
Bakken / Three Forks	2,639	5,282	8,702	9,316
El Halcón	566	1,613	2,840	2,708
Other	45	223	477	763
Total	3,250	7,118	12,019	12,787
Natural gas—MMcf				
Bakken / Three Forks	1,966	4,003	5,673	3,861
El Halcón	314	817	1,489	976
Other	731	1,740	2,961	3,975
Total	3,011	6,560	10,123	8,812
Natural gas liquids—MBbl				
Bakken / Three Forks	384	791	918	591
El Halcón	78	213	382	278
Other	39	92	157	244
Total	501	1,096	1,457	1,113
Production:				
Total MBoe[(1)]	4,253	9,307	15,163	15,369
Average daily production—Boe[(1)]	37,637	36,787	41,542	42,107
Average price per unit:[(2)]				
Crude oil price—Bbl	$ 43.01	$ 34.85	$ 42.63	$ 83.78
Natural gas price—Mcf	2.24	1.45	2.22	4.21
Natural gas liquids price—Bbl	12.01	7.23	9.35	33.66
Barrel of oil equivalent price—Boe[(1)]	35.87	28.53	36.17	74.56
Average cost per Boe:				
Production:				
Lease operating	$ 5.26	$ 5.38	$ 6.83	$ 8.47
Workover and other	2.47	2.42	1.38	1.05
Taxes other than income	2.91	2.63	3.22	6.92
Gathering and other	3.45	3.15	2.66	1.74

(1) *Natural gas reserves are converted to oil reserves using a ratio of six Mcf to one Bbl of oil. This ratio does not assume price equivalency and, given price differentials, the price for a barrel of oil equivalent for natural gas may differ significantly from the price for a barrel of oil.*

(2) *Amounts exclude the impact of cash paid or received on settled commodities derivative contracts as we did not elect to apply hedge accounting.*

The average crude oil and natural gas sales prices above do not reflect the impact of cash paid on, or cash received from, settled derivative contracts as these amounts are reflected as "*Net gain (loss) on derivative contracts*" in the consolidated statements of operations, consistent with our decision not to elect hedge accounting. Including this impact, during the period of September 10, 2016 through December 31, 2016 (Successor) and the period of January 1, 2016 through September 9, 2016 (Predecessor), average crude oil sales prices were $68.99 and $69.25 per Bbl and average natural gas sales prices were $2.33 and $1.58 per Mcf, respectively. For the year ended December 31, 2015 and 2014 (Predecessor), including the impact of our settled derivative contracts, average crude oil sales prices were $78.50 and $84.72 per Bbl and average natural gas sales prices were $3.06 and $4.06 per Mcf, respectively.

Competitive Conditions in the Business

The oil and natural gas industry is highly competitive and we compete with a substantial number of other companies that have greater financial and other resources. Many of these companies explore for, produce and market oil and natural gas, as well as carry on refining operations and market the resultant products on a worldwide basis. The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and natural gas properties, obtaining sufficient availability of drilling and completion equipment and services, obtaining purchasers and transporters of the oil and natural gas we produce and hiring and retaining key employees. There is also competition between oil and natural gas producers and other industries producing energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the government of the United States, the states in which our properties are located and tribal regulations in North Dakota. It is not possible to predict the nature of any such legislation or regulation which may ultimately be adopted or its effects upon our future operations. Such laws and regulations may substantially increase the costs of exploring for, developing or producing oil and natural gas and may prevent or delay the commencement or continuation of a given operation.

Other Business Matters

Markets and Major Customers

The purchasers of our oil and natural gas production consist primarily of independent marketers, major oil and natural gas companies and gas pipeline companies. Historically, we have not experienced any significant losses from uncollectible accounts. For the combined periods of September 10, 2016 through December 31, 2016 (Successor), and January 1, 2016 through September 9, 2016 (Predecessor), two individual purchasers of our production, Crestwood Midstream Partners, formerly Arrow Field Services LLC (Crestwood), and Suncor Energy Marketing Inc. (Suncor), each accounted for more than 10% of our total sales, collectively representing 58% of our total sales. In 2015 and 2014, three individual purchasers, Crestwood, Sunoco Inc. and Suncor, each accounted for more than 10% of our total sales, collectively representing 57% and 66% of our total sales for the year, respectively.

Seasonality of Business

Weather conditions affect the demand for, and prices of, natural gas and can also delay drilling activities, disrupting our overall business plans. Demand for natural gas is typically higher during the winter, resulting in higher natural gas prices for our natural gas production during our first and fourth fiscal quarters. Due to these seasonal fluctuations, our results of operations for individual quarterly periods may not be indicative of the results that we may realize on an annual basis.

Operational Risks

Oil and natural gas exploration and development involves a high degree of risk, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that we will discover or acquire additional oil and natural gas in commercial quantities. Oil and natural gas operations also involve the risk that well fires, blowouts, equipment failure, human error and other events may cause accidental releases of toxic or hazardous materials, such as petroleum liquids or drilling fluids into the environment, or cause significant injury to persons or property. In such event, substantial liabilities to third parties or governmental entities may be incurred, the satisfaction of which could substantially reduce available cash and possibly result in loss of oil and natural gas properties. Such hazards may also cause damage to or destruction of wells, producing formations, production facilities and pipeline or other processing facilities.

As is common in the oil and natural gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a material effect on our operating results, financial position or cash flows. For further discussion on risks see Item 1A. *Risk Factors*.

Regulations

All of the jurisdictions in which we own or operate producing oil and natural gas properties have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the plugging and abandonment of wells. Our operations are also subject to various conservation laws and regulations. These laws and regulations govern the size of drilling and spacing units, the density of wells that may be drilled in oil and natural gas properties and the unitization or pooling of oil and natural gas properties. In this regard, some states allow the forced pooling or integration of land and leases to facilitate exploration while other states rely primarily or exclusively on voluntary pooling of land and leases. In areas where pooling is primarily or exclusively voluntary, it may be difficult to form spacing units and therefore difficult to develop a project if the operator owns less than 100% of the leasehold. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose specified requirements regarding the ratability of production. On some occasions, tribal and local authorities have imposed moratoria or other restrictions on exploration and production activities pending investigations and studies addressing potential local impacts of these activities before allowing oil and natural gas exploration and production to proceed.

The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

Environmental Regulations

Our operations are subject to stringent federal, state, tribal and local laws regulating the discharge of materials into the environment or otherwise relating to health and safety or the protection of the environment. Numerous governmental agencies, such as the United States Environmental Protection

Agency, commonly referred to as the EPA, issue regulations to implement and enforce these laws, which often require difficult and costly compliance measures. Among other things, environmental regulatory programs typically govern the permitting, construction and operation of a facility. Many factors, including public perception, can materially impact the ability to secure an environmental construction or operation permit. Failure to comply with environmental laws and regulations may result in the assessment of substantial administrative, civil and criminal penalties, as well as the issuance of injunctions limiting or prohibiting our activities. In addition, some laws and regulations relating to protection of the environment may, in certain circumstances, impose strict liability for environmental contamination, which could result in liability for environmental damages and cleanup costs without regard to negligence or fault on our part.

Beyond existing requirements, new programs and changes in existing programs, may address various aspects of our business, including natural occurring radioactive materials, oil and natural gas exploration and production, air emissions, waste management, and underground injection of waste material. Environmental laws and regulations have been subject to frequent changes over the years, and the imposition of more stringent requirements could have a material adverse effect on our financial condition and results of operations. The following is a summary of the more significant existing environmental, health and safety laws and regulations to which our business operations are subject and for which compliance in the future may have a material adverse impact on our capital expenditures, earnings and competitive position.

Hazardous Substances and Wastes

The federal Comprehensive Environmental Response, Compensation and Liability Act, referred to as CERCLA or the Superfund law, and comparable state laws impose liability, without regard to fault, on certain classes of persons that are considered to be responsible for the release of a hazardous substance into the environment. These persons may include the current or former owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of hazardous substances that have been released at the site. Under CERCLA, these persons may be subject to joint and several liability for the costs of investigating and cleaning up hazardous substances that have been released into the environment, for damages to natural resources and for the costs of some health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment.

Under the federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, referred to as RCRA, most wastes generated by the exploration and production of oil and natural gas are not regulated as hazardous waste. Periodically, however, there are proposals to lift the existing exemption for oil and gas wastes and reclassify them as hazardous wastes or to subject them to enhanced solid waste regulation. If such proposals were to be enacted, they could have a significant impact on our operating costs and on those of all the industry in general. In the ordinary course of our operations moreover, some wastes generated in connection with our exploration and production activities may be regulated as solid waste under RCRA, as hazardous waste under existing RCRA regulations or as hazardous substances under CERCLA. From time to time, releases of materials or wastes have occurred at locations we own or at which we have operations. These properties and the materials or wastes released thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we have been and may be required to remove or remediate such materials or wastes.

Water Discharges

Our operations are also subject to the federal Clean Water Act and analogous state laws. Under the Clean Water Act, the EPA has adopted regulations concerning discharges of storm water runoff.

This program requires covered facilities to obtain individual permits, or seek coverage under a general permit. Some of our properties may require permits for discharges of storm water runoff and, as part of our overall evaluation of our current operations, we are upgrading storm water management practices at some facilities. We believe that we will be able to obtain, or be included under, these permits, where necessary, and will need to make only minor modifications to existing facilities and operations that would not have a material effect on us. The Clean Water Act and similar state acts regulate other discharges of wastewater, oil, and other pollutants to surface water bodies, such as lakes, rivers, wetlands, and streams. Failure to obtain permits for such discharges could result in civil and criminal penalties, orders to cease such discharges, and costs to remediate and pay natural resources damages. These laws also require the preparation and implementation of Spill Prevention, Control, and Countermeasure Plans in connection with on-site storage of significant quantities of oil. In the event of a discharge of oil into U.S. waters we could be liable under the Oil Pollution Act for clean up costs, damages and economic losses.

Our oil and natural gas production also generates salt water, which we dispose of by underground injection. The federal Safe Drinking Water Act (SDWA), the Underground Injection Control (UIC) regulations promulgated under the SDWA and related state programs regulate the drilling and operation of salt water disposal wells. The EPA directly administers the UIC program in some states, and in others it is delegated to the state for administering. Permits must be obtained before drilling salt water disposal wells, and casing integrity monitoring must be conducted periodically to ensure the casing is not leaking salt water to groundwater. Contamination of groundwater by oil and natural gas drilling, production, and related operations may result in fines, penalties, and remediation costs, among other sanctions and liabilities under the SDWA and state laws. In addition, third party claims may be filed by landowners and other parties claiming damages for alternative water supplies, property damages, and bodily injury.

Hydraulic Fracturing

Our completion operations are subject to regulation, which may increase in the short- or long-term. In particular, the well completion technique known as hydraulic fracturing, which is used to stimulate production of oil and natural gas, has come under increased scrutiny by the environmental community, and many local, state and federal regulators. Hydraulic fracturing involves the injection of water, sand and additives under pressure, usually down casing that is cemented in the wellbore, into prospective rock formations at depths to stimulate oil and natural gas production. We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with substantially all of the wells for which we are the operator.

Working at the direction of Congress, the EPA has completed a study finding that hydraulic fracturing could potentially harm drinking water resources under adverse circumstances such as injection directly into groundwater or into production wells lacking mechanical integrity. The EPA has also finalized pre-treatment standards under the Clean Water Act for wastewater discharges from shale hydraulic fracturing operations to municipal sewage treatment plants. Beyond that, several environmental groups have petitioned the EPA to extend toxic release reporting requirements under the Emergency Planning and Community Right-to-Know Act to the oil and natural gas extraction industry and to require disclosure under the Toxic Substances Control Act of chemicals used in fracturing. Congress might likewise consider legislation to amend the federal SDWA to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Certain states, including Colorado, Utah and Wyoming, already have issued similar disclosure rules.

In addition, the Department of the Interior has promulgated regulations concerning the use of hydraulic fracturing on lands under its jurisdiction, which includes lands on which we conduct or plan to conduct operations. States similarly have been imposing new restrictions or bans on hydraulic fracturing. Even local jurisdictions, such as Denton, Texas and several cities in Colorado, have adopted, or tried to adopt, regulations restricting hydraulic fracturing. Additional hydraulic fracturing requirements at the federal, state, tribal or local level may limit our ability to operate or increase our operating costs.

Air Emissions

The federal Clean Air Act and comparable state laws regulate emissions of various air pollutants through permitting programs and the imposition of other requirements. In addition, the EPA has developed and continues to develop stringent regulations governing emissions of toxic air pollutants at specified sources, including oil and natural gas production. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. Our operations, or the operations of service companies engaged by us, may in certain circumstances and locations be subject to permits and restrictions under these statutes for emissions of air pollutants.

In 2012 and 2016, the EPA issued air regulations for the oil and natural gas industry that address emissions from certain new sources of volatile organic compounds, sulfur dioxide, air toxics, and methane. The rules include the first federal air standards for natural gas and oil wells that are hydraulically fractured, or refractured, as well as requirements for other processes and equipment, including storage tanks. Compliance with these regulations has imposed additional requirements and costs on our operations. The EPA also has started to consider whether to extend such regulations to existing wells.

In October 2015, the EPA announced that it was lowering the primary national ambient air quality standard for ozone from 75 parts per billion to 70 parts per billion. Implementation will take place over several years; however, the new standard could result in a significant expansion of ozone nonattainment areas across the United States, including areas in which we operate. Oil and natural gas operations in ozone nonattainment areas would likely be subject to increased regulatory burdens in the form of more stringent emission controls, emission offset requirements, and increased permitting delays and costs.

Climate Change

Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth's atmosphere. In response increasingly governments have been adopting domestic and international climate change regulations that require reporting and reductions of the emission of such greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of burning oil, natural gas and refined petroleum products, are considered greenhouse gases. Internationally, the United Nations Framework Convention on Climate Change, the Kyoto Protocol and the Paris Agreement address greenhouse gas emissions, and several countries, including those comprising the European Union, have established greenhouse gas regulatory systems. In the United States, at the state level, many states, either individually or through multi-state regional initiatives, have been implementing legal measures to reduce emissions of greenhouse gases, primarily through emission inventories, emissions targets, greenhouse gas cap and trade programs or incentives for renewable energy generation, while others have considered adopting such greenhouse gas programs.

At the federal level, the EPA has issued regulations requiring us and other companies to annually report certain greenhouse gas emissions from our oil and natural gas facilities. Beyond its measuring and reporting rules, the EPA has issued an "Endangerment Finding" under section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of current and future generations. The finding served as the first step in issuing regulations that require permits for and reductions in greenhouse gas emissions for certain facilities.

In addition, the Obama Administration developed a Strategy to Reduce Methane Emissions that was intended to result by 2025 in a 40-45% decrease in methane emissions from the oil and gas industry as compared to 2012 levels. Consistent with that strategy, the EPA issued its air rules for oil and gas production sources, and the federal Bureau of Land Management (BLM) promulgated standards for reducing venting and flaring on public lands.

Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur additional operating costs, such as costs to purchase and operate emissions control systems or other compliance costs, and reduce demand for our products.

The National Environmental Policy Act

Oil and natural gas exploration and production activities may be subject to the National Environmental Policy Act, or NEPA. NEPA requires federal agencies, including the Department of the Interior, to evaluate major agency actions that have the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay the development of oil and natural gas projects.

Threatened and endangered species, migratory birds, and natural resources

Various state and federal statutes prohibit certain actions that adversely affect endangered or threatened species and their habitat, migratory birds, wetlands, and natural resources. These statutes include the Endangered Species Act, the Migratory Bird Treaty Act and the Clean Water Act. The United States Fish and Wildlife Service may designate critical habitat areas that it believes are necessary for survival of threatened or endangered species. A critical habitat designation could result in further material restrictions on federal land use or on private land use and could delay or prohibit land access or development. Where takings of or harm to species or damages to wetlands, habitat, or natural resources occur or may occur, government entities or at times private parties may act to prevent or restrict oil and gas exploration activities or seek damages for any injury, whether resulting from drilling or construction or releases of oil, wastes, hazardous substances or other regulated materials, and in some cases, criminal penalties, may result.

Occupational Safety and Health Act

We are subject to the requirements of the federal Occupational Safety and Health Act and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the Occupational Safety and Health Administration's hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees.

Employees and Principal Office

As of December 31, 2016 (Successor), we had 245 full-time employees. We hire independent contractors on an as needed basis. We have no collective bargaining agreements with our employees. We believe that our employee relationships are satisfactory.

As of December 31, 2016 (Successor), we leased corporate office space in Houston, Texas at 1000 Louisiana Street, where our principal offices are located. We also lease corporate office space in Denver, Colorado as well as a number of other field office locations.

Access to Company Reports

We file periodic reports, proxy statements and other information with the SEC in accordance with the requirements of the Securities Exchange Act of 1934, as amended. We make our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and Forms 3, 4 and 5 filed on behalf of directors and officers, and any amendments to such reports, available free of charge through our corporate website at *www.halconresources.com* as soon as reasonably practicable after such reports are filed with, or furnished to, the SEC. In addition, our insider trading policy, regulation FD policy, equity-based incentive grant policy, corporate governance guidelines, code of conduct, code of ethics, audit committee charter, compensation committee charter, nominating and corporate governance committee charter and reserves committee charter are available on our website under the heading "Investor Relations—Corporate Governance". Within the time period required by the SEC and the NYSE, as applicable, we will post on our website any modifications to the code of conduct and the code of ethics for our Chief Executive Officer and senior financial officers and any waivers applicable to senior officers as defined in the applicable code, as required by the Sarbanes-Oxley Act of 2002. You may also read and copy any document we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, our reports, proxy and information statements, and our other filings are also available to the public over the internet at the SEC's website at *www.sec.gov*. Unless specifically incorporated by reference in this Annual Report on Form 10-K, information that you may find on our website is not part of this report.

ITEM 1A. RISK FACTORS

Oil and natural gas prices are volatile, and low prices could have a material adverse impact on our business.

Our revenues, profitability and future growth and the carrying value of our properties depend substantially on prevailing oil and natural gas prices. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. The amount we will be able to borrow under our Senior Credit Agreement will be subject to periodic redeterminations based in part on current oil and natural gas prices and on changing expectations of future prices. Lower prices may also reduce the amount of oil and natural gas that we can economically produce and have an adverse effect on the value of our properties.

Historically, the markets for oil and natural gas have been volatile, and they are likely to continue to be volatile in the future. Among the factors that can cause volatility are:

- the domestic and foreign supply of oil and natural gas;
- the ability of members of the Organization of Petroleum Exporting Countries and other producing countries to agree upon and maintain oil prices and production levels;
- social unrest and political instability, particularly in major oil and natural gas producing regions outside the United States, such as the Middle East, and armed conflict or terrorist attacks, whether or not in oil or natural gas producing regions;
- the level of consumer product demand;
- the growth of consumer product demand in emerging markets, such as China;
- labor unrest in oil and natural gas producing regions;
- weather conditions, including hurricanes and other natural occurrences that affect the supply and/or demand of oil and natural gas;
- the price and availability of alternative fuels;

• the price of foreign imports;

• worldwide economic conditions; and

• the availability of liquid natural gas imports.

These external factors and the volatile nature of the energy markets make it difficult to estimate future prices of oil and natural gas.

Our actual financial results may vary materially from the projections that we filed with the bankruptcy court in connection with the confirmation of our plan of reorganization.

In connection with the disclosure statement we filed with the bankruptcy court, and the hearing to consider confirmation of our plan of reorganization, we prepared projected financial information to demonstrate to the bankruptcy court the feasibility of the plan of reorganization and our ability to continue operations upon our emergence from bankruptcy. Those projections were prepared solely for the purpose of the bankruptcy proceedings and have not been, and will not be, updated on an ongoing basis and should not be relied upon by investors. At the time they were prepared, the projections reflected numerous assumptions concerning our anticipated future performance and with respect to prevailing and anticipated market and economic conditions that were and remain beyond our control and that may not materialize. Projections are inherently subject to substantial and numerous uncertainties and to a wide variety of significant business, economic and competitive risks and the assumptions underlying the projections and/or valuation estimates may prove to be wrong in material respects. Actual results will likely vary significantly from those contemplated by the projections. As a result, investors should not rely on these projections.

Our historical financial information may not be indicative of our future financial performance.

On the effective date of our emergence from bankruptcy on September 9, 2016 we adopted fresh-start accounting, as a consequence of which our assets and liabilities were adjusted to fair values and we have no beginning or ending retained earnings or deficit balances. Accordingly, our financial condition and results of operations following our emergence from chapter 11 bankruptcy will not be comparable to the financial condition and results of operations reflected in our historical financial statements. Further, as a result of the implementation of our plan of reorganization and the transactions contemplated thereby, our historical financial information may not be indicative of our future financial performance.

Upon our emergence from bankruptcy, the composition of our Board of Directors changed significantly.

Under the plan of reorganization, the composition of our Board of Directors (the Board) changed significantly from an eleven member Board with terms of one year to, upon emergence, a nine member Board, structured into three tiers and classified into staggered three year terms. Only three of our current directors served on our Board previously and a total of six of our directors were designated by Franklin Advisors, Inc. and Ares Management LLC. Our new directors have different backgrounds, experiences and perspectives from those individuals who previously served on the Board and, thus, may have different views on the issues that will determine our future.

There may be circumstances in which the interests of our significant stockholders could be in conflict with the interests of our other stockholders.

As of December 31, 2016, funds advised by Franklin Advisors, Inc. and Ares Management LLC held approximately 36% and 19%, respectively, of our post-reorganization common stock. Circumstances may arise in which these stockholders may have an interest in pursuing or preventing acquisitions, divestitures or other transactions, including the issuance of additional shares or debt, that, in their judgment, could enhance their investment in us or another company in which they invest. Such transactions might adversely affect us or other holders of our common stock. In addition, our significant concentration of share ownership may adversely affect the trading price of our common shares because investors may perceive disadvantages in owning shares in companies with significant stockholders.

Future sales of our common stock in the public market or the issuance of securities senior to our common stock, or the perception that these sales may occur, could adversely affect the trading price of our common stock and our ability to raise funds in stock offerings.

A large percentage of our shares of common stock are held by a relatively small number of investors. Further, we entered into registration rights agreements with certain of those investors pursuant to which we have agreed to file a registration statement with the SEC to facilitate potential future sales of such shares by them. Sales by us or our stockholders of a substantial number of shares of our common stock in the public markets, or even the perception that these sales might occur (such as upon the filing of the aforementioned registration statement), could cause the market price of our common stock to decline or could impair our ability to raise capital through a future sale of, or pay for acquisitions using, our equity securities.

We are currently authorized to issue 1.0 billion shares of common stock and 1.0 million shares of preferred stock, with such designations, rights, preferences, privileges and restrictions as determined by the Board. As of December 31, 2016, we had outstanding approximately 93.0 million shares of common stock and warrants and options to purchase an aggregate of 10.1 million shares of our common stock. On February 27, 2017 (Successor), we issued in a private placement, 5,518 shares of new 8% automatically convertible preferred stock, each share of which is convertible into 10,000 shares of common stock. The common stock issuable upon a conversion of the preferred stock represents approximately 37% of our outstanding common stock as of December 31, 2016 on an as-converted basis, or approximately 55.2 million shares of common stock.

As of December 31, 2016, we have also reserved an additional 1.7 million shares for future issuance to our directors, officers and employees as restricted stock or stock option awards pursuant to our 2016 Long-Term Incentive Plan. The potential issuance of such additional shares of common stock may create downward pressure on the trading price of our common stock.

We may issue common stock or other equity securities senior to our common stock in the future for a number of reasons, including to finance acquisitions, to adjust our leverage ratio, and to satisfy our obligations upon the exercise of warrants and options, or for other reasons. We cannot predict the effect, if any, that future sales or issuances of shares of our common stock or other equity securities, or the availability of shares of common stock or such other equity securities for future sale or issuance, will have on the trading price of our common stock.

We may have difficulty financing our planned capital expenditures which could adversely affect our growth.

Our business requires substantial capital expenditures primarily to fund our drilling program. We may also continue to selectively increase our acreage position, which would require capital in addition to the capital necessary to drill on our existing acreage. In addition, it is possible that we will acquire acreage in other areas that we believe are prospective for oil and natural gas production and expend capital to develop such acreage. We expect to use borrowings under our Senior Credit Agreement and proceeds from potential future capital markets transactions, if necessary, to fund capital expenditures that are in excess of our operating cash flow and cash on hand.

Our Senior Credit Agreement limits our borrowings to the lesser of the borrowing base and the total commitments. As of December 31, 2016, our Senior Credit Agreement had a borrowing base of approximately $600.0 million. As of December 31, 2016, we had $186.0 million of indebtedness outstanding, $6.7 million of letters of credit outstanding and $407.3 million of borrowing capacity available under our Senior Credit Agreement. Our borrowing base is determined semi-annually, and may also be redetermined periodically at the discretion of our lenders. A reduction in our borrowing base could require us to repay any indebtedness in excess of the borrowing base. Our Senior Credit Agreement also contains certain financial covenants, including the maintenance of (i) a Total Net Indebtedness Leverage Ratio (as defined in the Senior Credit Agreement) not to exceed 4.75:1.00 initially, determined as of each four fiscal quarter periods and commencing with the fiscal quarter ending September 30, 2016, stepping down to 4.50:1.00 and 4.00:1.00 on September 30, 2017 and March 31, 2019, respectively, and (ii) a Current Ratio (as defined in the Senior Credit Agreement) not to be less than 1.00:1.00, commencing with the fiscal quarter ending December 31, 2016. In the event we have difficulty meeting the total net indebtedness leverage ratio test or the current ratio test in the future, we would be required to seek additional relief, and there is no assurance that it would be granted.

Additionally, the indentures governing our senior debt contain covenants limiting our ability to incur additional indebtedness, including borrowings under our Senior Credit Agreement, unless we meet one of two alternative tests. The first test applies to all indebtedness and requires that, after giving effect to the incurrence of additional debt, our fixed charge coverage ratio (which is the ratio of our adjusted consolidated EBITDA (as defined in our indentures) to our adjusted consolidated interest expense over the trailing four fiscal quarters) will be at least 2.0 to 1.0. The second test allows us to incur additional indebtedness, beyond the limitations of the fixed charge coverage ratio test, as long as this additional debt is incurred under Credit Facilities (as defined in our indentures) and generally, the amount thereof is not more than, subject to certain exceptions, the greater of (i) $900 million, (ii) the borrowing base in effect under our Senior Credit Agreement, and (iii) 30% of our adjusted consolidated net tangible assets, or ACNTA. ACNTA is defined in all of our indentures and is determined primarily by the value of discounted future net revenues from proved oil and natural gas reserves plus the capitalized cost attributable to our unevaluated properties. Currently, we are permitted to incur additional indebtedness under these incurrence tests, but may be limited in the future. Lower oil and natural gas prices in the future could reduce our adjusted consolidated EBITDA, as well as our ACNTA, and thus could reduce our ability to incur additional indebtedness.

Additionally, our ability to complete future equity offerings is limited by general market conditions. If we are not able to borrow sufficient amounts under our Senior Credit Agreement and/or are unable to raise sufficient capital to fund our capital expenditures, we may be required to curtail our drilling, development, land acquisition and other activities, which could result in a decrease in our production of oil and natural gas, forfeiture of leasehold interests if we are unable or unwilling to renew them, and could force us to sell some of our assets on an untimely or unfavorable basis, each of which could have a material adverse effect on our results and future operations.

We may be required to take non-cash asset write downs.

We may be required under full cost accounting rules to write down the carrying value of oil and natural gas properties if oil and natural gas prices do not improve or if there are substantial downward adjustments to our estimated proved reserves, increases in our estimates of development costs or deterioration in our exploration results. We utilize the full cost method of accounting for oil and natural gas exploration and development activities. Under full cost accounting, we are required by SEC regulations to perform a ceiling test each quarter. The ceiling test is an impairment test and generally establishes a maximum, or "ceiling," of the book value of oil and natural gas properties that is equal to the expected after tax present value (discounted at 10%) of the future net cash flows from proved reserves, including the effect of cash flow hedges when hedge accounting is applied, calculated using the unweighted arithmetic average of the first day of each month for the 12-month period ending at the balance sheet date. If the net book value of oil and natural gas properties (reduced by any related net deferred income tax liability and asset retirement obligation) exceeds the ceiling limitation, SEC regulations require us to impair or "write down" the book value of our oil and natural gas properties.

In the past, due to the sustained decline in the unweighted 12-month average price of oil and natural gas used in the ceiling test calculations, we recorded full cost ceiling test impairments. During 2015, the net book value of our oil and natural gas properties at March 31, June 30, September 30, and December 31, 2015 exceeded the respective ceiling amounts for each quarter end. As a result, we recorded full cost ceiling test impairments before income taxes totaling $2.6 billion for the year ended December 31, 2015 (Predecessor). The ceiling test impairments in 2015 were driven by decreases in the first-day-of-the-month average prices for crude oil from $94.99 per Bbl at December 31, 2014 (Predecessor) to $50.28 per Bbl at December 31, 2015 (Predecessor).

During 2016, the net book value of our oil and natural gas properties at March 31, June 30, and September 30, 2016 exceeded the respective ceiling amounts for each quarter end. As a result, we recorded full cost ceiling test impairments before income taxes of $420.9 million for the period of September 10, 2016 through September 30, 2016 (Successor) and $754.8 million for the period January 1, 2016 through September 9, 2016 (Predecessor). The impairment at September 30, 2016 primarily reflects the pricing differences between the first-day-of-the-month average price for the preceding twelve months required by Regulation S-X, Rule 4-10 and ASC 932 used in calculating the ceiling test and the forward-looking prices required by ASC 852 to estimate the fair value of the Company's oil and natural gas properties on the fresh-start reporting date, September 9, 2016. The ceiling test impairments at March 31 and June 30, 2016 were driven by decreases in the first-day-of-the-month average prices for crude oil used in the ceiling test calculations since December 31, 2015. As ceiling test computations depend in part upon the calculated unweighted arithmetic average prices and oil and natural gas prices are inherently volatile, sustained lower commodity prices will continue to have a material impact upon our full cost ceiling test calculation. Continued write downs of oil and natural gas properties may occur until such time as commodity prices have recovered, and remained at recovered levels, so as to increase the 12-month average price used in the ceiling calculation. Depending on the magnitude, a ceiling test write down could materially affect our results of operations.

Costs associated with unevaluated properties, which were approximately $316.4 million at December 31, 2016 (Successor), are not initially subject to the ceiling test limitation. Rather, we assess all items classified as unevaluated property on a quarterly basis for possible impairment or reduction in value based upon our intentions with respect to drilling on such properties, the remaining lease term, geological and geophysical evaluations, drilling results, the assignment of proved reserves, and the economic viability of development if proved reserves are assigned. These factors are significantly influenced by our expectations regarding future commodity prices, development costs, and access to capital at acceptable cost. During any period in which these factors indicate impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to depletion and the ceiling test limitation. Accordingly, a significant change in these factors, many of which are beyond our control, may shift a significant amount of cost from unevaluated properties into the full cost pool that is subject to depletion and the ceiling test limitation.

Historically, we have had substantial indebtedness and we may incur substantially more debt in the future. Higher levels of indebtedness make us more vulnerable to economic downturns and adverse developments in our business.

We have incurred debt amounting to approximately $964.7 million as of December 31, 2016 (Successor). In addition, on February 16, 2017 (Successor), we issued $850.0 million aggregate principal amount of new 6.75% senior unsecured notes due 2025 in a private placement exempt from registration under the Securities Act of 1933, as amended, afforded by Rule 144A and Regulation S, and applicable state securities laws. The net proceeds from the private placement will fund the repurchase and redemption of all $700 million of our outstanding 2020 Second Lien Notes. As a result of our indebtedness, we will need to use a portion of our cash flow to pay interest, which will reduce the amount we will have available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate. Our indebtedness under our Senior Credit Agreement is at a variable interest rate, and so a rise in interest rates will generate greater interest expense to the extent we do not have hedging arrangements that are effective in mitigating interest rate fluctuations. The amount of our debt may also cause us to be more vulnerable to economic downturns and adverse developments in our business.

We may incur substantially more debt in the future. The indentures governing our outstanding senior notes contain restrictions on our incurrence of additional indebtedness. These restrictions, however, are subject to a number of qualifications and exceptions, and under certain circumstances, we could incur substantial additional indebtedness in compliance with these restrictions. Moreover, these restrictions do not prevent us from incurring obligations that do not constitute "indebtedness" as defined under the indentures. At December 31, 2016 (Successor), our Senior Credit Agreement had a borrowing base of approximately $600.0 million. At December 31, 2016 (Successor), we had $186.0 million of indebtedness outstanding, $6.7 million of letters of credit outstanding and $407.3 million of borrowing capacity available under our Senior Credit Agreement.

Our ability to meet our debt obligations and other expenses will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors, many of which we are unable to control. If our cash flow is not sufficient to service our debt, we may be required to refinance debt, sell assets or sell additional shares of common or preferred stock on terms that we may not find attractive if it may be done at all. Further, our failure to comply with the financial and other restrictive covenants relating to our indebtedness could result in a default under that indebtedness, which could adversely affect our business, financial condition and results of operations.

Our ability to use net operating loss carryforwards to offset future taxable income for U.S. federal income tax purposes is subject to limitation.

In general, under Section 382 of the Internal Revenue Code of 1986, as amended, a corporation that undergoes an "ownership change" is subject to limitations on its ability to utilize its pre-change net operating losses (NOLs), to offset future taxable income. In general, an ownership change occurs if the aggregate stock ownership of certain stockholders (generally 5% shareholders, applying certain look-through rules) increases by more than 50 percentage points over such stockholders' lowest percentage ownership during the testing period (generally three years).

We believe we experienced an ownership change in September 2016 as a result of the consummation of our plan of reorganization under chapter 11 of the U.S. Bankruptcy Code. Limitations imposed on our ability to use NOLs to offset future taxable income may cause U.S. federal income taxes to be paid earlier than otherwise would be paid if such limitations were not in effect and could cause such NOLs to expire unused, in each case reducing or eliminating the benefit of such NOLs. Similar rules and limitations may apply for state income tax purposes.

We depend on computer and telecommunications systems and failures in our systems or cyber security attacks could significantly disrupt our business operations.

We have entered into agreements with third parties for hardware, software, telecommunications and other information technology services in connection with our business. In addition, we have developed proprietary software systems, management techniques and other information technologies incorporating software licensed from third parties. It is possible we could incur interruptions from cyber security attacks, computer viruses or malware. We believe that we have positive relations with our related vendors and maintain adequate anti-virus and malware software and controls; however, any interruptions to our arrangements with third parties to our computing and communications infrastructure or our information systems could significantly disrupt our business operations.

A downgrade in our credit rating could negatively impact our cost of and ability to access capital.

As of the date of this filing, our corporate credit rating was "B−" with a stable outlook by Standard and Poor's (S&P) and "B3" with a stable outlook by Moody's Investors Service (Moody's). Although we are not aware of any current plans of these or other rating agencies to lower their respective ratings on us or our senior debt, we cannot be assured that our credit ratings will not be downgraded. A downgrade in our credit ratings could negatively impact our cost of capital and our ability to effectively execute aspects of our strategy. If our credit rating were downgraded, it could be difficult for us to raise debt in the public debt markets and the cost of that new debt could be higher than debt we could raise with our current ratings. In addition, a downgrade could impact requirements for us to provide financial assurance of performance under contractual arrangements or derivative agreements.

We may not be able to drill wells on a substantial portion of our acreage.

We may not be able to drill on a substantial portion of our acreage for various reasons. We may not generate or be able to raise sufficient capital to do so. Commodities pricing may also make drilling some acreage uneconomic. Our actual drilling activities and future drilling budget will depend on drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, lease expirations, gathering system and pipeline transportation constraints, regulatory approvals and other factors. In addition, any drilling activities we are able to conduct may not be successful or add additional proved reserves to our overall proved reserves, which could have a material adverse effect on our future business, financial condition and results of operations.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage.

As of December 31, 2016 (Successor), we owned leasehold interests in approximately 113,000 net acres in the Utica/Point Pleasant formation (Utica). Our current drilling plans for 2017 do not include any drilling or completion activities on our Utica acreage. Unless production in paying quantities is established on units containing these leases during their terms or unless we pay (to the extent we have the contractual right to pay) delay rentals or obtain other extensions to maintain the lease, these leases will expire. If our leases expire, we will lose our right to develop the related properties.

Our drilling plans are subject to change based upon various factors, many of which are beyond our control, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals. Further, some of our acreage is located in sections where we do not hold the majority of the acreage and therefore it is likely that we will not be named operator of these sections. As a non-operating leaseholder we have less control over the timing of drilling and are therefore subject to additional risk of expirations.

We depend substantially on the continued presence of key personnel for critical management decisions and industry contacts.

Our success depends upon the continued contributions of our executive officers and key employees, particularly with respect to providing the critical management decisions and contacts necessary to manage and maintain growth within a highly competitive industry. Competition for qualified personnel can be intense, particularly in the oil and natural gas industry, and there are a limited number of people with the requisite knowledge and experience. Under these conditions, we could be unable to attract and retain these personnel. The loss of the services of any of our executive officers or other key employees for any reason could have a material adverse effect on our business, operating results, financial condition and cash flows.

Our ability to sell our production and/or receive market prices for our production may be adversely affected by transportation capacity constraints and interruptions.

If the amount of natural gas, condensate or oil being produced by us and others exceeds the capacity of the various transportation pipelines and gathering systems available in our operating areas, it will be necessary for new transportation pipelines and gathering systems to be built. Or, in the case of oil and condensate, it will be necessary for us to rely more heavily on trucks to transport our production, which is more expensive and less efficient than transportation via pipeline. The construction of new pipelines and gathering systems is capital intensive and construction may be postponed, interrupted or cancelled in response to changing economic conditions and the availability and cost of capital. In addition, capital constraints could limit our ability to build gathering systems to transport our production to transportation pipelines. In such event, costs to transport our production may increase materially or we might have to shut in our wells awaiting a pipeline connection or capacity and/or sell our production at much lower prices than market or than we currently project, which would adversely affect our results of operations.

A portion of our production may also be interrupted, or shut in, from time to time for numerous other reasons, including as a result of weather conditions (which may worsen due to climate changes), accidents, loss of pipeline or gathering system access, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could adversely affect our cash flow.

Unless we replace our reserves, our reserves and production will decline, which would adversely affect our financial condition, results of operations and cash flows.

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Decline rates are typically greatest early in the productive life of a well. Estimates of the decline rate of an oil or natural gas well are inherently imprecise, and are less precise with respect to new or emerging oil and natural gas formations with limited production histories than for more developed formations with established production histories. Our production levels and the reserves that we currently expect to recover from our wells will change if production from our existing wells declines in a different manner than we have estimated and can change under other circumstances. Thus, our future oil and natural gas reserves and production and, therefore, our cash flow and results of operations are highly dependent upon our success in efficiently developing and exploiting our current properties and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs. If we are unable to replace our current and future production, our cash flows and the value of our reserves may decrease, adversely affecting our business, financial condition, results of operations, cash flows and potentially the borrowing capacity under our Senior Credit Agreement.

Estimates of proved oil and natural gas reserves involve assumptions and any material inaccuracies in these assumptions will materially affect the quantities and the value of our reserves.

This Annual Report on Form 10-K contains estimates of our proved oil and natural gas reserves. These estimates are based upon various assumptions, including assumptions required by the SEC relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil and natural gas reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from those estimated. Any significant variance could materially affect the estimated quantities and the value of our reserves. Our properties may also be susceptible to hydrocarbon drainage from production by other operators on adjacent properties. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

At December 31, 2016 (Successor), approximately 42% of our estimated proved reserves were classified as proved undeveloped. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we will make significant capital expenditures to develop our reserves. The estimates of these oil and natural gas reserves and the costs associated with development of these reserves have been prepared in accordance with SEC regulations, however, actual capital expenditures will likely vary from estimated capital expenditures, development may not occur as scheduled and actual results may not be as estimated.

Our oil and natural gas activities are subject to various risks which are beyond our control.

Our operations are subject to many risks and hazards incident to exploring and drilling for, producing, transporting, marketing and selling oil and natural gas. Although we may take precautionary measures, many of these risks and hazards are beyond our control and unavoidable under the circumstances. Many of these risks or hazards could materially and adversely affect our revenues and expenses, the ability of certain of our wells to produce oil and natural gas in commercial quantities, the rate of production and the economics of the development of, and our investment in the prospects in which we have or will acquire an interest. Any of these risks and hazards could materially and adversely affect our financial condition, results of operations and cash flows. Such risks and hazards include:

- human error, accidents, labor force and other factors beyond our control that may cause personal injuries or death to persons and destruction or damage to equipment and facilities;
- blowouts, fires, hurricanes, pollution and equipment failures that may result in damage to or destruction of wells, producing formations, production facilities and equipment;
- unavailability of materials and equipment;
- engineering and construction delays;
- unanticipated transportation costs and delays;
- unfavorable weather conditions;
- hazards resulting from unusual or unexpected geological or environmental conditions;
- environmental regulations and requirements;
- accidental leakage of toxic or hazardous materials, such as petroleum liquids, drilling fluids or salt water, into the environment;

- hazards resulting from the presence of hydrogen sulfide (H_2S) or other contaminants in gas we produce;
- changes in laws and regulations, including laws and regulations applicable to oil and natural gas activities or markets for the oil and natural gas produced;
- fluctuations in supply and demand for oil and natural gas causing variations of the prices we receive for our oil and natural gas production; and
- the availability of alternative fuels and the price at which they become available.

As a result of these risks, expenditures, quantities and rates of production, revenues and operating costs may be materially affected and may differ materially from those anticipated by us.

Our exploration and development drilling efforts and the operation of our wells may not be profitable or achieve our targeted returns.

We require significant amounts of undeveloped leasehold acreage to further our development efforts. Exploration, development, drilling and production activities are subject to many risks, including the risk that commercially productive reservoirs will not be discovered. We invest in property, including undeveloped leasehold acreage, which we believe will result in projects that will add value over time. However, we cannot guarantee that our leasehold acreage will be profitably developed, that new wells drilled by us will be productive or that we will recover all or any portion of our investment in such leasehold acreage or wells. Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient net reserves to return a profit after deducting operating and other costs. In addition, wells that are profitable may not achieve our targeted rate of return. Our ability to achieve our target results are dependent upon the current and future market prices for oil and natural gas, costs associated with producing oil and natural gas and our ability to add reserves at an acceptable cost.

In addition, we may not be successful in controlling our drilling and production costs to improve our overall return. The cost of drilling, completing and operating a well is often uncertain and cost factors can adversely affect the economics of a project. We cannot predict the cost of drilling and completing a well, and we may be forced to limit, delay or cancel drilling operations as a result of a variety of factors, including:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents and shortages or delays in the availability of drilling and completion equipment and services;
- adverse weather conditions, including hurricanes; and
- compliance with governmental requirements.

We are subject to various contractual limitations that affect the discretion of our management in operating our business.

The indentures governing our debt and our Senior Credit Agreement contain various provisions that may limit our management's discretion in certain respects. In particular, these agreements limit our and our subsidiaries' ability to, among other things:

- pay dividends on, redeem or repurchase shares of our common stock and, under certain circumstances, our convertible preferred stock, and redeem or repurchase our subordinated debt;
- make loans to others;

- make investments;
- incur additional indebtedness;
- create certain liens;
- sell assets;
- enter into agreements that restrict dividends or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all or substantially all of our assets and those of our restricted subsidiaries taken as a whole;
- engage in transactions with affiliates;
- enter into hedging contracts;
- create unrestricted subsidiaries; and
- enter into sale and leaseback transactions.

Compliance with these and other limitations may limit our ability to operate and finance our business and engage in certain transactions in the manner we might otherwise. In addition, if we fail to comply with the limitations under our indentures or Senior Credit Agreement, our creditors, if the agreements so provide, may accelerate the related indebtedness as well as any other indebtedness to which a cross-acceleration or cross-default provision applies. In addition, lenders may be able to terminate any commitments they had made to make further funds available to us.

Our business is highly competitive.

The oil and natural gas industry is highly competitive in many respects, including identification of attractive oil and natural gas properties for acquisition, drilling and development, securing financing for such activities and obtaining the necessary equipment and personnel to conduct such operations and activities. In seeking suitable opportunities, we compete with a number of other companies, including large oil and natural gas companies and other independent operators with greater financial resources, larger numbers of personnel and facilities, and, in some cases, with more expertise. There can be no assurance that we will be able to compete effectively with these entities.

The unavailability or high cost of drilling rigs, pressure pumping equipment and crews, other equipment, supplies, water, personnel and oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget.

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies, water or qualified personnel. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. In addition, the demand for, and wage rates of, qualified drilling rig crews rise as the number of active rigs in service increases. Increasing levels of exploration and production may increase the demand for oilfield services and equipment, and the costs of these services and equipment may increase, while the quality of these services and equipment may suffer. The unavailability or high cost of drilling rigs, pressure pumping equipment, supplies or qualified personnel can materially and adversely affect our operations and profitability. In order to secure drilling rigs and pressure pumping equipment, we have entered into certain contracts that extend over several months and or years. If demand for drilling rigs and pressure pumping equipment subside during the period covered by these contracts, the price we are required to pay may be significantly more than the market rate for similar services.

We are subject to complex federal, state, local and other laws and regulations that frequently are amended to impose more stringent requirements that could adversely affect the cost, manner or feasibility of doing business.

Companies that explore for and develop, produce, sell and transport oil and natural gas in the United States are subject to extensive federal, state and local laws and regulations, including complex tax and environmental, health and safety laws and the corresponding regulations, and are required to obtain various permits and approvals from federal, state and local agencies. If these permits are not issued or unfavorable restrictions or conditions are imposed on our drilling activities, we may not be able to conduct our operations as planned. We may be required to make large expenditures to comply with governmental regulations. Matters subject to regulation include:

- water discharge and disposal permits for drilling operations;
- drilling bonds;
- drilling permits;
- reports concerning operations;
- air quality, air emissions, noise levels and related permits;
- spacing of wells;
- rights-of-way and easements;
- unitization and pooling of properties;
- pipeline construction;
- gathering, transportation and marketing of oil and natural gas;
- taxation; and
- waste transport and disposal permits and requirements.

Failure to comply with applicable laws may result in the suspension or termination of operations and subject us to liabilities, including administrative, civil and criminal penalties. Compliance costs can be significant. Moreover, the laws governing our operations or the enforcement thereof could change in ways that substantially increase the costs of doing business. Any such liabilities, penalties, suspensions, terminations or regulatory changes could materially and adversely affect our business, financial condition and results of operations.

Under environmental, health and safety laws and regulations, we also could be held liable for personal injuries, property damage (including site clean-up and restoration costs) and other damages including the assessment of natural resource damages. Such laws may impose strict as well as joint and several liability for environmental contamination, which could subject us to liability for the conduct of others or for our own actions that were in compliance with all applicable laws at the time such actions were taken. Environmental and other governmental laws and regulations also increase the costs to plan, design, drill, install, operate and abandon oil and natural gas wells. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain drilling projects. Part of the regulatory environment in which we operate includes, in some cases, federal requirements for performing or preparing environmental assessments, environmental impact studies and/or plans of development before commencing exploration and production activities. In addition, our activities are subject to regulation by oil and natural gas producing states relating to conservation practices and protection of correlative rights. The North Dakota Industrial Commission (NDIC), the State's chief energy regulator, for example, approved comprehensive rules in 2016 for the conservation of crude oil and natural gas that address site construction, gathering pipelines and spill containment. Such regulations affect our operations and limit the quantity of oil and natural gas we may produce and sell. Delays in obtaining regulatory approvals or necessary permits, the failure to obtain a permit or the receipt of a permit with excessive conditions or costs could have a material adverse effect on our ability to explore on, develop or produce our properties. Additionally, the oil and natural gas regulatory environment could change in ways that might substantially increase the financial and managerial costs to comply with the requirements of these laws and regulations and, consequently, adversely affect our profitability. By way of example, in 2015 the EPA lowered the primary national ambient air quality standard for ozone from 75 parts per billion to 70 parts per billion. Implementation will take place over several years; however, the new standard eventually could result in more stringent emissions controls and additional permitting obligations for our operations.

Part of our strategy involves drilling in shale formations, using horizontal drilling and completion techniques. The results of our drilling program using these techniques may be subject to more uncertainties than conventional drilling programs, especially in areas that are new and emerging. These uncertainties could result in an inability to meet our expectations for reserves and production.

The results of our drilling in shale formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas have limited or no production history; consequently our predictions of drilling results in these areas are more uncertain. In addition, the use of horizontal drilling and completion techniques used in all of our shale formations involve certain risks and complexities that do not exist in conventional wells. The ultimate success of our drilling and completion strategies and techniques will be better evaluated over time as more wells are drilled and production profiles are better established.

If our drilling results are less than anticipated our investment in these areas may not be as attractive as we anticipate and could result in material write downs of unevaluated properties and future declines in the value of our undeveloped acreage.

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

We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with many of the wells for which we are the operator. Federal, state, tribal and local governments have been adopting or considering restrictions on or prohibitions of fracturing in areas where we currently conduct operations, or in the future plan to conduct operations. Consequently, we could be subject to additional levels of regulation, operational delays or increased operating costs and could have additional regulatory burdens imposed upon us that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

From time to time, for example, legislation has been proposed in Congress to amend the federal SDWA to require federal permitting of hydraulic fracturing and the disclosure of chemicals used in the hydraulic fracturing process. Further, the EPA completed a study finding that hydraulic fracturing could potentially harm drinking water resources under adverse circumstances such as injection directly into groundwater or into production wells lacking mechanical integrity. Other governmental reviews have also been recently conducted or are under way that focus on environmental aspects of hydraulic fracturing. For example, a federal BLM rulemaking for hydraulic fracturing practices on federal and Indian lands resulted in a 2015 final rule that requires public disclosure of chemicals used in hydraulic fracturing, confirmation that the wells used in fracturing operations meet proper construction standards and development of plans for managing related flowback water. These activities could result in additional regulatory scrutiny that could make it difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

Certain states, including North Dakota and Texas where we conduct a majority of our operations, likewise are considering or have adopted more stringent requirements for various aspects of hydraulic fracturing operations, such as permitting, disclosure, air emissions, well construction, seismic monitoring, waste disposal and water use. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general or hydraulic fracturing in particular. Such efforts have extended to bans on hydraulic fracturing.

The proliferation of regulations may limit our ability to operate. If the use of hydraulic fracturing is limited, prohibited or subjected to further regulation, these requirements could delay or effectively prevent the extraction of oil and natural gas from formations which would not be economically viable without the use of hydraulic fracturing. This could have a material adverse effect on our business, financial condition, results of operations and cash flows.

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

Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth's atmosphere. In response, increasingly governments have been adopting domestic and international climate change regulations that require reporting and reductions of the emission of such greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of burning oil, natural gas and refined petroleum products, are considered greenhouse gases. Internationally, the United Nations Framework Convention on Climate Change, the Kyoto Protocol and the Paris Agreement address greenhouse gas emissions, and international negotiations over climate change and greenhouse gases are continuing. Meanwhile, several countries, including those comprising the European Union, have established greenhouse gas regulatory systems.

In the United States, many states, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through emission inventories, emission targets, greenhouse gas cap and trade programs or incentives for renewable energy generation, while others have considered adopting such greenhouse gas programs.

At the federal level, the Obama Administration pledged for the Paris Agreement to meet an economy-wide target in 2025 of reducing greenhouse gas emissions by 26-28% below the 2005 level. To help achieve these reductions, federal agencies have been addressing climate change through a variety of administrative actions. The EPA thus issued greenhouse gas monitoring and reporting regulations that cover oil and natural gas facilities, among other industries. Beyond measuring and reporting, the EPA issued an "Endangerment Finding" under section 202(a) of the Clean Air Act, concluding certain greenhouse gas pollution threatens the public health and welfare of current and future generations. The finding served as the first step to issuing regulations that require permits for and reductions in greenhouse gas emissions for certain facilities. In March 2014, moreover, then President Obama released a Strategy to Reduce Methane Emissions that included consideration of both voluntary programs and targeted regulations for the oil and gas sector. Consistent with that strategy, the EPA issued final rules in 2016 for new and modified oil and gas production sources (including hydraulically fractured oil wells, natural gas well sites, natural gas processing plants, natural gas gathering and boosting stations and natural gas transmission sources) to reduce emissions of methane as well as volatile organic compound and toxic pollutants. In addition, the BLM has promulgated standards for reducing venting and flaring on public lands. The EPA and BLM actions are part of a series of steps by the Obama Administration that were intended to result by 2025 in a 40-45% decrease in methane emissions from the oil and gas industry as compared to 2012 levels.

In the courts, several decisions have been issued that may increase the risk of claims being filed by governments and private parties against companies that have significant greenhouse gas emissions. Such cases may seek to challenge air emissions permits that greenhouse gas emitters apply for and seek to force emitters to reduce their emissions or seek damages for alleged climate change impacts to the environment, people, and property.

The direction of future U.S. climate change regulation is difficult to predict given the current uncertainties surrounding the policies of the Trump Administration. The EPA may or may not continue developing regulations to reduce greenhouse gas emissions from the oil and gas industry. Even if federal efforts in this area slow, states may continue pursuing climate regulations. Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur additional operating costs, such as costs to purchase and operate emissions controls, to obtain emission allowances or to pay emission taxes, and reduce demand for our products.

Requirements to reduce gas flaring in North Dakota could have an adverse effect on our operations.

Wells in the Bakken / Three Forks formations in North Dakota, where we have significant operations, yield natural gas as a byproduct of oil production. Bottlenecks in the gas gathering network in certain areas resulted in some of that natural gas being flared instead of processed. In 2014, the NDIC, the State's chief energy regulator, issued an order to reduce the volume of natural gas flared from oil wells in the Bakken / Three Forks formations. The State's current objectives are to cause operators to capture 85% of the natural gas by November 1, 2016, 88% by November 1, 2018 and 91-93% by November 1, 2020. In addition, the NDIC is requiring operators to develop gas capture plans that describe how much natural gas is expected to be produced, how it will be delivered to a processor and where it will be processed. Production caps or penalties will be imposed on certain wells that cannot meet the capture goals. These capture requirements and any similar future obligations in North Dakota or our other locations, may increase our operational costs or restrict our production, which could materially and adversely affect our financial condition, results of operations and cash flows.

Crude oil from the Bakken / Three Forks formations may pose unique hazards that may have an adverse effect on our operations.

The United States Department of Transportation (USDOT) has concluded that crude oil from the Bakken / Three Forks formations has a higher volatility than most other crude oil from the United States and thus is more ignitable and flammable. Based on that information, and several fires involving rail transportation of crude oil, USDOT imposed additional requirements for shipping crude oil by rail. Beyond that, the rail industry has adopted increased precautions for crude shipments. Any restrictions that significantly affect transportation of crude oil production could materially and adversely affect our financial condition, results of operations and cash flows.

Operations on the Fort Berthold Indian Reservation of the Three Affiliated Tribes in North Dakota are subject to various federal and tribal regulations and laws, any of which may increase our costs and delay our operations.

Various federal agencies within the U.S. Department of the Interior, particularly the Office of Natural Resources Revenue (formerly the Minerals Management Service) and the Bureau of Indian Affairs, along with the Three Affiliated Tribes, promulgate and enforce regulations pertaining to operations on the Fort Berthold Indian Reservation on which we hold approximately 28,500 net acres. In addition, the Three Affiliated Tribes is a sovereign nation having the right to enforce laws and regulations independent from federal, state and local statutes and regulations. These tribal laws and regulations include various taxes, fees and other conditions that apply to lessees, operators and contractors conducting operations on Native American tribal lands. Lessees and operators conducting operations on tribal lands can be subject to the Native American tribal court system. One or more of these factors may increase our costs of doing business on the Fort Berthold Indian Reservation and may have an adverse impact on our ability to effectively transport products within the Fort Berthold Indian Reservation or to conduct our operations on such lands.

Our operations substantially depend on the availability of water. Restrictions on our ability to obtain, dispose of or recycle water may impact our ability to execute our drilling and development plans in a timely or cost-effective manner.

Water is an essential component of our drilling and hydraulic fracturing processes. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce oil, natural gas liquids and natural gas, which could have an adverse effect on our business, financial condition and results of operations. Wastewaters from our operations typically are disposed of via underground injection. Some studies have linked earthquakes in certain areas to underground injection, which is leading to greater public scrutiny of disposal wells. Any new environmental initiatives or regulations that restrict injection of fluids, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of oil and gas, or that limit the withdrawal, storage or use of surface water or ground water necessary for hydraulic fracturing of our wells, could increase our operating costs and cause delays, interruptions or cessation of our operations, the extent of which cannot be predicted, and all of which would have an adverse effect on our business, financial condition, results of operations and cash flows.

The ongoing implementation of federal legislation enacted in 2010 could have an adverse impact on our ability to use derivative instruments to reduce the effects of commodity prices, interest rates and other risks associated with our business.

Historically, we have entered into a number of commodity derivative contracts in order to hedge a portion of our oil and natural gas production. On July 21, 2010, then President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, which requires the SEC and the Commodity Futures Trading Commission (or CFTC), along with other federal agencies, to promulgate regulations implementing the new legislation.

The CFTC has finalized other regulations implementing the Dodd-Frank Act's provisions regarding trade reporting, margin, clearing, and trade execution; however, some regulations remain to be finalized and it is not possible at this time to predict when the CFTC will adopt final rules. For example, the CFTC has re-proposed regulations setting position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions are expected to be made exempt from these limits. Also, it is possible that under recently adopted margin rules, some registered swap dealers may require us to post initial and variation margins in connection with certain swaps not subject to central clearing.

The Dodd-Frank Act and any additional implementing regulations could significantly increase the cost of some commodity derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of some commodity derivative contracts, limit our ability to trade some derivatives to hedge risks, reduce the availability of some derivatives to protect against risks we encounter, and reduce our ability to monetize or restructure our existing commodity derivative contracts. If we reduce our use of derivatives as a consequence, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Increased volatility may make us less attractive to certain types of investors. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. If the implementing regulations result in lower commodity prices, our revenues could be adversely affected. Any of these consequences could adversely affect our business, financial condition and results of operations.

We will be subject to risks in connection with acquisitions, and the integration of significant acquisitions may be difficult and may involve unexpected costs or delays.

We have completed in the past and may complete in the future significant acquisitions of reserves, properties, prospects and leaseholds and other strategic transactions that appear to fit within our overall business strategy, which may include the acquisition of asset packages of producing properties or existing companies or businesses operating in our industry. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil, natural gas and natural gas liquids prices and their appropriate differentials;
- development and operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and potential recoverable reserves. Inspections may not always be performed on every well or well site, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We are generally not able to obtain contractual indemnification for environmental liabilities and normally acquire properties on an "as is" basis.

Significant acquisitions of existing companies or businesses and other strategic transactions may involve additional risks, including:

- diversion of our management's attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;
- the challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with our own while carrying on our ongoing business;
- difficulty associated with coordinating geographically separate organizations;
- the challenge of integrating environmental compliance systems to meet requirements of rapidly changing regulations;
- the challenge of attracting and retaining personnel associated with acquired operations; and
- failure to realize the full benefit that we expect in estimated proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition, or to realize these benefits within our expected time frame.

The process of integrating operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to manage the integration process effectively, or if any significant business activities are interrupted as a result of the integration process, our business could be materially and adversely affected.

We cannot be certain that the insurance coverage maintained by us will be adequate to cover all losses that may be sustained in connection with all oil and natural gas activities.

We maintain general and excess liability policies, which we consider to be reasonable and consistent with industry standards. These policies generally cover:

- personal injury;
- bodily injury;
- third party property damage;
- medical expenses;
- legal defense costs;
- pollution in some cases;
- well blowouts in some cases; and
- workers compensation.

As is common in the oil and natural gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a material effect on our financial position, results of operations and cash flows. There can be no assurance that the insurance coverage that we maintain will be sufficient to cover claims made against us in the future.

Title to the properties in which we have an interest may be impaired by title defects.

We generally obtain title opinions on significant properties that we drill or acquire. However, there is no assurance that we will not suffer a monetary loss from title defects or title failure. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. Generally, under the terms of the operating agreements affecting our properties, any monetary loss is to be borne by all parties to any such agreement in proportion to their interests in such property. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

We depend on the skill, ability and decisions of third-party operators of the oil and natural gas properties in which we have a non-operated working interest.

The success of the drilling, development and production of the oil and natural gas properties in which we have or expect to have a non-operating working interest is substantially dependent upon the decisions of such third-party operators and their diligence to comply with various laws, rules and regulations affecting such properties. The failure of any third-party operator to make decisions, perform their services, discharge their obligations, deal with regulatory agencies, and comply with laws, rules and regulations, including environmental laws and regulations, in a proper manner with respect to properties in which we have an interest could result in material adverse consequences to our interest in such properties, including substantial penalties and compliance costs. Such adverse consequences could result in substantial liabilities to us or reduce the value of our properties, which could materially affect our results of operations.

Hedging transactions may limit our potential gains and increase our potential losses.

In order to manage our exposure to price risks in the marketing of our oil, natural gas, and natural gas liquids production, we have entered into oil, natural gas, and natural gas liquids price hedging arrangements with respect to a portion of our anticipated production and we may enter into additional hedging transactions in the future. While intended to reduce the effects of volatile commodity prices, such transactions may limit our potential gains and increase our potential losses if commodity prices were to rise substantially over the price established by the hedge. In addition, such transactions may expose us to the risk of loss in certain circumstances, including instances in which:

- our production is less than expected;
- there is a widening of price differentials between delivery points for our production; or
- the counterparties to our hedging agreements fail to perform under the contracts.

We are currently out of compliance with the New York Stock Exchange's average market capitalization requirement and are at risk of the NYSE delisting our common stock, which could materially impair the liquidity and value of our common stock.

Our common stock is currently listed on the New York Stock Exchange (NYSE). On August 12, 2016, we were notified by the NYSE that the average market capitalization of our common stock was less than $50 million over a 30 trading day period, at the same time as our stockholders' equity was less than $50 million. In accordance with NYSE rules, we timely submitted a plan to regain compliance with the average market capitalization requirement, which we successfully executed as a consequence of our emergence from chapter 11 bankruptcy effective September 9, 2016. However, the NYSE has indicated it may take up to two calendar quarters for notice from the NYSE that compliance has been regained.

A delisting of our common stock, either as result of a failure to regain compliance with the NYSE's average market capitalization requirement or the Company's failure to satisfy other qualitative or quantitative standards for continued listing on the NYSE, could reduce the liquidity and market price of our common stock.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

A description of our properties is included in Item 1. *Business* and is incorporated herein by reference.

We believe that we have satisfactory title to the properties owned and used in our business, subject to liens for taxes not yet payable, liens incident to minor encumbrances, liens for credit arrangements and easements and restrictions that do not materially detract from the value of these properties, our interests in these properties, or the use of these properties in our business. We believe that our properties are adequate and suitable for us to conduct business in the future.

ITEM 3. LEGAL PROCEEDINGS

A description of our legal proceedings is included in Item 8. *Consolidated Financial Statements and Supplementary Data*—Note 11*, "Commitments and Contingencies,"* and is incorporated herein by reference.

From time to time, we are a party to litigation or other legal proceedings that we consider to be a part of the ordinary course of our business. We are not currently involved in any legal proceedings, nor are we a party to any pending or threatened claims, that could reasonably be expected to have a material adverse effect on our financial condition or results of operations.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Our Successor common stock trades on the New York Stock Exchange (NYSE) under the symbol HK. On September 9, 2016, upon emergence from chapter 11 bankruptcy, all existing shares of our Predecessor common stock were cancelled and the Successor Company issued approximately 90.0 million shares of new common stock which began trading on the NYSE on September 12, 2016. The following table sets forth the quarterly high and low sales prices per share of our Successor common stock as reported on the NYSE from September 12, 2016 through December 31, 2016. Refer to *Item 8. Consolidated Financial Statements and Supplementary Data*—Note 2, "*Reorganization,*" for further details.

	High	Low
2016		
Period from September 12, 2016 through September 30, 2016	$12.01	$7.58
Fourth Quarter	11.29	8.01

We intend to retain earnings for use in the operation and expansion of our business and therefore do not anticipate declaring cash dividends on our common stock in the foreseeable future. Any future determination to pay dividends on common stock will be at the discretion of the Board and will be dependent upon then existing conditions, including our prospects, and such other factors, as the Board deems relevant. We are also restricted from paying cash dividends on common stock under our Senior Credit Agreement and under the terms of the indentures governing our other long-term debt.

Approximately 727 registered stockholders of record as of February 23, 2017 held our common stock. In many instances, a stockholder can hold shares through a broker or other entity holding shares in street name for one or more customers who beneficially own the shares.

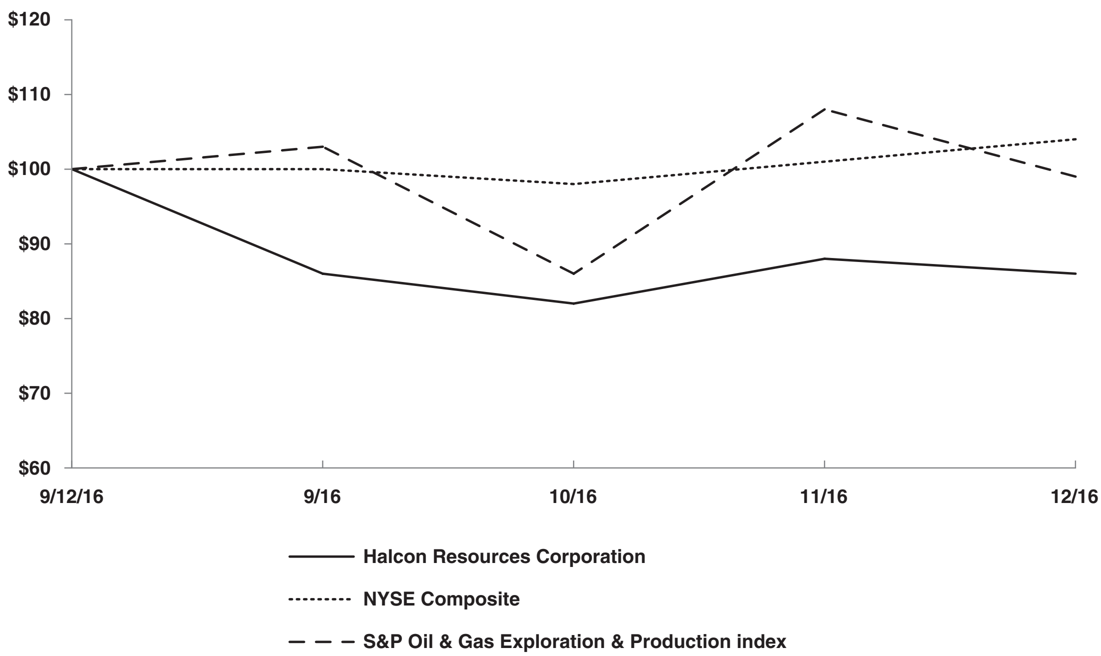
Changes in Securities, Use of Proceeds and Issuer Purchases of Equity Securities

There were no purchases of equity securities during the three months ended December 31, 2016 (Successor).

Stock Performance Graph

The following graph and table compare the cumulative total return to our stockholders on our Successor common stock beginning September 12, 2016 through December 31, 2016, relative to the cumulative total returns of the NYSE Composite Index and the S&P Oil & Gas Exploration & Production Index for the same period. The comparison assumes an investment of $100 (with reinvestment of all dividends at the average of the closing stock prices at the beginning and end of the quarter) was made in our Successor common stock on September 12, 2016, and in each of the indexes, and relative performance is tracked through December 31, 2016. The identity of the companies included in the S&P Oil & Gas Exploration & Production Index will be provided upon request.

COMPARISON OF 4 MONTH CUMULATIVE TOTAL RETURN*
Among Halcón Resources Corporation, the NYSE Composite Index,
and S&P Oil & Gas Exploration & Production index



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* *100 invested on 9/12/16 in stock or 8/31/16 in index, including reinvestment of dividends. Fiscal year ending December 31.*

Value of Initial $100 Investment

	September 12, 2016	September 30, 2016	October 31, 2016	November 30, 2016	December 31, 2016
Halcón Resources Corporation	$100	$ 86	$82	$ 88	$ 86
NYSE Composite	100	100	98	101	104
S&P Oil & Gas Exploration & Production Index	100	103	86	108	99

ITEM 6. SELECTED FINANCIAL DATA

Prior year financial statements are not comparable to our current year financial statements due to the adoption of fresh-start accounting. References to "Successor" or "Successor Company" relate to the financial position and results of operations of the reorganized Company subsequent to September 9, 2016. References to "Predecessor" or "Predecessor Company" relate to the financial position and results of operations of the Company prior to, and including, September 9, 2016.

The following table presents selected historical financial data derived from our consolidated financial statements. The following data is only a summary and should be read with our historical consolidated financial statements and related notes contained in this document. Refer to the footnotes in Item 8. *Consolidated Financial Statements and Supplementary Data,* for details regarding our recent reorganization and adoption of fresh-start accounting, as well as other transactions that could impact the comparability of the following data (in thousands, except per share data):

	Successor	Predecessor				
	Period from September 10, 2016 through December 31, 2016(7)	Period from January 1, 2016 through September 9, 2016(8)	Years Ended December 31,			
			2015(9)	2014(10)	2013(11)	2012
Income Statement Data:						
Total operating revenues	$ 153,362	$ 266,843	$ 550,278	$1,148,261	$ 999,506	$ 248,322
Income (loss) from operations	(415,799)	(851,617)	(2,744,506)	(58,387)	(1,290,947)	(29,717)
Net income (loss)	(479,193)	11,958	(1,922,621)	315,956	(1,222,622)	(53,885)
Net income (loss) available to common stockholders	(479,984)	(32,794)	(2,006,958)	282,942	(1,233,407)	(142,330)
Net income (loss) per share of common stock(1):						
Basic	$ (5.26)	$ (0.27)	$ (18.66)	$ 3.40	$ (16.25)	$ (4.55)
Diluted	$ (5.26)	$ (0.27)	$ (18.66)	$ 2.93	$ (16.25)	$ (4.55)

	Successor	Predecessor			
	As of December 31, 2016	As of December 31,			
		2015	2014	2013	2012
Balance sheet data:					
Working capital (deficit)	$ (46,904)	$ 261,345	$ (41,977)	$ (325,756)	$ (390,111)
Total assets	1,319,670	3,458,692	6,383,227	5,298,986	5,002,320
Total long-term debt, net(2)(3)	964,653	2,873,637	3,695,488	3,126,318	1,995,793
Redeemable noncontrolling interest(4)	—	183,986	117,166	—	—
Preferred stock(5)	—	—	—	—	695,238
Stockholders' equity(6)	112,688	52,414	1,772,169	1,447,610	1,397,982

(1) *No cash dividends on our common stock were declared or paid for any periods presented.*

(2) *Excludes current portion of long-term debt for all periods presented.*

(3) *On September 9, 2016, upon emergence from chapter 11 bankruptcy, approximately $1.9 billion of our senior notes were cancelled. Refer to Item 8. Consolidated Financial Statements and Supplementary Data—Note 2, "Reorganization," for additional information.*

(4) *On June 16, 2014, HK TMS, LLC (HK TMS), which was then a wholly owned subsidiary of the Company, entered into a transaction with funds and accounts managed by Apollo Global Management, LLC (Apollo), by initially selling 150,000 preferred shares in HK TMS (Membership Interests), which then held all of our acreage in the Tuscaloosa Marine Shale, located in Mississippi and Louisiana. On September 30, 2016, Apollo acquired one hundred percent of the common shares of HK TMS and assumed all obligations relating to the Membership Interests. For additional information regarding these transactions, see Item 8. Consolidated Financial Statements and Supplementary Data—Note 5, "Divestitures" and Note 12, "Mezzanine Equity."*

(5) Predecessor preferred stock outstanding at December 31, 2012 converted into 21.8 million shares of our Predecessor common stock on January 18, 2013, following stockholder approval.

(6) On September 9, 2016, upon emergence from chapter 11 bankruptcy, all existing shares of Predecessor common stock were cancelled and the Successor Company issued approximately 90.0 million shares of new common stock in total to the Predecessor Company's existing common stockholders, Third Lien Noteholders, Unsecured Noteholders, and the Convertible Noteholder. Refer to Item 8. Consolidated Financial Statements and Supplementary Data—Note 2, "Reorganization," for further details.

(7) For the period from September 10, 2016 through December 31, 2016 (Successor), we incurred a $420.9 million full cost ceiling impairment on the carrying value of our oil and natural gas properties. Refer to Item 8. Consolidated Financial Statements and Supplementary Data—Note 6, "Oil and Natural Gas Properties," for additional information.

(8) For the period from January 1, 2016 through September 9, 2016 (Successor), we incurred a $754.8 million full cost ceiling impairment on the carrying value of our oil and natural gas properties, a $28.1 million impairment on other operating property and equipment, an $81.4 million gain on extinguishment of debt, and a $913.7 million gain on reorganization items due to fresh-start accounting. Refer to the footnotes in Item 8. Consolidated Financial Statements and Supplementary Data, for additional information regarding these events.

(9) For the year ended December 31, 2015 (Predecessor), we incurred a $2.6 billion full cost ceiling impairment on the carrying value of our oil and natural gas properties. Refer to Item 8. Consolidated Financial Statements and Supplementary Data—Note 6,"Oil and Natural Gas Properties," for additional information regarding this impairment.

(10) For the year ended December 31, 2014 (Predecessor), we incurred the following charges, a $239.7 million full cost ceiling impairment on the carrying value of oil and natural gas properties and a $35.6 million impairment on other operating property and equipment. Refer to the footnotes included in Item 8. Consolidated Financial Statements and Supplementary Data, for additional information regarding these impairments.

(11) For the year ended December 31, 2013 (Predecessor), we incurred the following charges which contributed to our net loss for the year, a $1.1 billion full cost ceiling impairment on the carrying value of our oil and natural gas properties, a $228.9 million goodwill impairment, and a $67.5 million impairment of other operating property and equipment.

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

The following discussion is intended to assist in understanding our results of operations and our current financial condition. Our consolidated financial statements and the accompanying notes included elsewhere in this Annual Report on Form 10-K contain additional information that should be referred to when reviewing this material.

Prior year financial statements are not comparable to our current year financial statements due to the adoption of fresh-start accounting. References to "Successor" or "Successor Company" relate to the financial position and results of operations of the reorganized Company subsequent to September 9, 2016. References to "Predecessor" or "Predecessor Company" relate to the financial position and results of operations of the Company prior to, and including, September 9, 2016.

Statements in this discussion may be forward-looking. These forward-looking statements involve risks and uncertainties, including those discussed below, which could cause actual results to differ from those expressed.

Overview

We are an independent energy company focused on the acquisition, production, exploration and development of onshore liquids-rich oil and natural gas assets in the United States. We were incorporated in Delaware on February 5, 2004, recapitalized on February 8, 2012 and reorganized on September 9, 2016. During 2012, we focused our efforts on the acquisition of unevaluated leasehold and producing properties in select prospect areas. In the years since, we have primarily focused on the development of acquired properties and also divested non-core assets in order to fund activities in our core resource plays. Our oil and natural gas assets consist of proved reserves and undeveloped acreage positions in unconventional liquids-rich basins/fields, providing us with an extensive drilling inventory in multiple basins that we believe allow for multiple years of production and broad flexibility to direct our capital resources to projects with the greatest potential returns. As discussed below in more detail under *"Recent Developments,"* we have recently acquired certain properties in the Southern Delaware Basin for $705.0 million and entered into an agreement to sell our assets located in the El Halcón area of East Texas for $500.0 million, which is expected to close by early March 2017.

At December 31, 2016 (Successor), our estimated total proved oil and natural gas reserves, as prepared by our independent reserve engineering firm, Netherland, Sewell & Associates, Inc. (Netherland, Sewell), using Securities and Exchange Commission (SEC) prices of $42.75 per Bbl of oil and $2.481 per MMBtu of natural gas, were approximately 148.6 MMBoe, consisting of 119.6 MMBbls of oil, 15.6 MMBbls of natural gas liquids, and 80.2 Bcf of natural gas. Approximately 58% of our proved reserves were classified as proved developed as of December 31, 2016 (Successor). We maintain operational control of approximately 95% of our proved reserves.

Our total operating revenues for the period of September 10, 2016 through December 31, 2016 (Successor) and the period of January 1, 2016 through September 9, 2016 (Predecessor) were approximately $153.4 million and $266.8 million, respectively, or $420.2 million combined, compared to total operating revenues for 2015 of $550.3 million. The decrease in total operating revenues year over year was driven by the sustained decline in the prices of crude oil and, to a lesser extent, natural gas along with a decrease in our average daily production year over year. During the period of September 10, 2016 through December 31, 2016 (Successor) and the period of January 1, 2016 through September 9, 2016 (Predecessor), production averaged 37,637 Boe/d and 36,787 Boe/d, respectively, or 37,049 Boe/d combined, compared to average daily production of 41,542 Boe/d during 2015 (Predecessor). In response to the sustained decline in commodity prices we reduced our drilling and completion activities in 2016, running only one rig on average in our most economic drilling area. In

2016 (for the combined Successor and Predecessor periods), we participated in the drilling of 90 gross (30.6 net) wells, all of which were completed and capable of production.

Our financial results depend upon many factors, but are largely driven by the volume of our oil and natural gas production and the price that we receive for that production. Our production volumes will decline as reserves are depleted unless we expend capital in successful development and exploration activities or acquire properties with existing production. The amount we realize for our production depends predominantly upon commodity prices and our related commodity price hedging activities, which are affected by changes in market demand and supply, as impacted by overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. Accordingly, finding and developing oil and natural gas reserves at economical costs is critical to our long-term success.

In 2016, (for the combined Successor and Predecessor periods) we incurred capital expenditures for drilling and completions of approximately $183.9 million. We expect to spend approximately $300 million on drilling and completion capital expenditures during 2017. In addition, we expect to spend approximately $15 million on infrastructure, seismic and other in 2017. Approximately 65% of our 2017 drilling and completion budget is expected to be spent in the Bakken/Three Forks formations in North Dakota and approximately 35% is budgeted for the Southern Delaware Basin. Our 2017 drilling and completion budget currently contemplates growing to four (on average) operated rigs during the second quarter of 2017, is based on our current view of market conditions and current business plans, and is subject to change.

We expect to fund our budgeted 2017 capital expenditures with cash flows from operations and, to a lesser extent, borrowings under our Senior Credit Agreement. We strive to maintain financial flexibility and may access capital markets as necessary to maintain substantial borrowing capacity under our Senior Credit Agreement, facilitate drilling on our large undeveloped acreage position and permit us to selectively expand our acreage position and infrastructure projects. In the event our cash flows are materially less than anticipated and other sources of capital we historically have utilized are not available on acceptable terms, we may further curtail our capital spending.

Oil and natural gas prices are inherently volatile and have declined dramatically since mid-year 2014. In response to this we have significantly curtailed our capital spending, reduced operating costs, and have incurred substantial asset impairments, primarily as a result of the full cost ceiling test calculation. The ceiling test calculation dictates that we use the unweighted arithmetic average price of crude oil and natural gas as of the first day of each month for the 12-month period ending at the balance sheet date. Using the crude oil price for February 2017 of $53.88 per Bbl, and holding it constant for one month to create a trailing 12-month period of average prices that is more reflective of recent price trends, our ceiling test limitation would not have generated an impairment at December 31, 2016 holding all other inputs and factors constant. Sustained lower commodity prices would have a material impact upon our full cost ceiling test calculation. In addition to commodity prices, our production rates, levels of proved reserves, future development costs, transfers of unevaluated properties, capital spending and other factors will determine our actual ceiling test calculation and impairment analyses in future periods.

Recent Developments

Issuance of 2025 Senior Notes and Repurchase of 2020 Second Lien Notes

On February 16, 2017 (Successor), we issued $850.0 million aggregate principal amount of our new 6.75% senior unsecured notes due 2025 (the 2025 Notes) in a private placement exempt from registration under the Securities Act of 1933, as amended (Securities Act), afforded by Rule 144A and Regulation S, and applicable state securities laws. The 2025 Notes were issued at par and bear interest at a rate of 6.75% per annum, payable semi-annually on February 15 and August 15 of each year, beginning on August 15, 2017. Proceeds from the private placement were approximately $835.1 million after deducting initial purchasers' discounts and commissions and offering expenses. We utilized a portion of the net proceeds from the private placement to fund the repurchase of the outstanding 2020 Second Lien Notes and will use an additional amount of the net proceeds to redeem the remaining amount of such notes, discussed further below, and for general corporate purposes.

On February 9, 2017 (Successor), we commenced a cash tender offer for any and all of our 2020 Second Lien Notes and on February 15, 2017, we received approximately $289.2 million or 41% of the outstanding aggregate principal amount of the 2020 Second Lien Notes which were validly tendered (and not validly withdrawn). As a result, on February 16, 2017 (Successor), we paid approximately $303.5 million for approximately $289.2 million principal amount of 2020 Second Lien Notes, a make-whole premium of $13.2 million plus accrued and unpaid interest of approximately $1.1 million to repurchase such notes pursuant to the tender offer and issued a redemption notice to redeem the remaining 2020 Second Lien Notes. The remaining $410.8 million aggregate principal amount of outstanding 2020 Second Lien Notes will be repurchased through the guaranteed delivery procedures or redeemed at a price of 104.313% of the principal amount thereof, plus accrued and unpaid interest to, but not including, the redemption date. The redemption date is expected to be March 20, 2017.

Pending Divestiture of East Texas Eagle Ford Assets

On January 24, 2017 (Successor), certain of our subsidiaries entered into an Agreement of Sale and Purchase with a subsidiary of Hawkwood Energy, LLC (Hawkwood) for the sale of all of our oil and natural gas properties and related assets located in the Eagle Ford formation of East Texas (the El Halcón Assets) for a total sales price of $500.0 million (the El Halcón Divestiture). The effective date of the proposed sale is January 1, 2017, and we expect to close the transaction in early March 2017. The sale properties include approximately 80,500 net acres prospective for the Eagle Ford formation in East Texas. As of December 31, 2016, estimated proved reserves from these properties were approximately 35.1 MMBoe, or 24% of our estimated year-end 2016 proved reserves. The sale includes approximately 191 gross (135 net) wells that produced approximately 7,600 Boe/d (80% oil) for the year ended December 31, 2016.

The sales price is subject to adjustments for (i) operating expenses, capital expenditures and revenues between the effective date and the closing date, (ii) title, casualty and environmental defects, and (iii) other purchase price adjustments customary in oil and gas purchase and sale agreements. Pursuant to the terms of the agreement, Hawkwood paid into escrow a deposit of $32.5 million at signing, which amount will be applied to the sales price if the transaction closes.

The completion of the El Halcón Divestiture is subject to customary closing conditions. The parties may terminate the sale agreement if certain closing conditions have not been satisfied, if total adjustments to the sales price exceed 20% of the sales price, or $100.0 million, or the transaction has not closed on or before March 20, 2017. If one or more of the closing conditions are not satisfied, or if the transaction is otherwise terminated, the divestiture may not be completed. There can be no assurance that we will sell the El Halcón Assets on the terms or timing described or at all. If the El Halcón Divestiture closes, we intend to use the net proceeds to repay amounts outstanding under our Senior Credit Agreement and for general corporate purposes.

Private Placement of Automatically Convertible Preferred Stock

On January 24, 2017 (Successor), we entered into a stock purchase agreement with certain accredited investors to sell, in a private placement exempt from the registration requirements of the Securities Act pursuant to Section 4(a)(2), approximately 5,518 shares of 8% automatically convertible preferred stock, par value $0.0001 per share, each share of which will be convertible into 10,000 shares of common stock, par value $0.0001 per share (or a proportionate number of shares of common stock with respect to any fractional shares of preferred stock issued), for gross proceeds of approximately

$400.1 million, equivalent to a placement at $7.25 per common share. We used the net proceeds from the sale of the preferred stock to partially fund the Pecos County Acquisition.

The preferred stock will convert automatically into common stock on the 20th calendar day after we mail a definitive information statement to holders of our common stock notifying them that holders of a majority of our outstanding common stock consented to the issuance of common stock upon conversion of the preferred stock on January 24, 2017 (Successor). The initial conversion price is subject to adjustment in certain circumstances, including stock splits, stock dividends, rights offerings, or combinations of our common stock. No dividends will be due on the convertible preferred stock if it converts into common stock on or before June 1, 2017. The common stock issuable upon a conversion of the preferred stock represents approximately 37% of our outstanding common stock as of December 31, 2016 on an as-converted basis.

We have agreed to file a registration statement to register the resale of the shares of common stock issuable upon conversion of the preferred stock and to pay penalties in the event such registration is not effective by June 27, 2017.

Acquisition of Southern Delaware Basin Assets (Pecos and Reeves Counties, Texas)

On January 18, 2017 (Successor), we entered into a Purchase and Sale Agreement with Samson Exploration, LLC (Samson), pursuant to which we agreed to acquire a total of 20,901 net acres and related assets in the Southern Delaware Basin located in Pecos and Reeves Counties, Texas (collectively, the Pecos County Assets), for a total purchase price of $705.0 million (the Pecos County Acquisition). The effective date of the acquisition was November 1, 2016, and we closed the transaction on February 28, 2017.

Based on information provided by Samson, we estimate that current net production from the Pecos County Assets is approximately 2,600 Boe/d (72% oil, 15% NGLs, 13% natural gas). We estimate that the Pecos County Assets include a 75% average working interest, with approximately 44% held by production. After closing, we plan to operate two rigs.

The purchase price was subject to adjustments for (i) operating expenses, capital expenditures and revenues between the effective date and the closing date, (ii) title, casualty and environmental defects, and (iii) other purchase price adjustments customary in oil and gas purchase and sale agreements. We funded the Pecos County Acquisition with the net proceeds from the private placement of our preferred stock and borrowings under our Senior Credit Agreement.

Following the agreement with Samson, we have agreed to acquire additional interests in the acreage from a non-operating owner for approximately $22.3 million. This incremental acquisition includes 594 additional net acres and approximately 160 Boe/d of current production and is expected to close in early March 2017.

Option Agreement to Acquire Southern Delaware Basin Assets (Ward County, Texas)

On December 9, 2016 (Successor), we entered into an agreement with a private company, pursuant to which we have acquired the rights to purchase up to 15,040 net acres located in Ward and Winkler Counties, Texas (the Ward County Assets) prospective for the Wolfcamp and Bone Spring formations. The Ward County Assets are divided into two tracts: the Southern Tract, comprising 6,720 net acres, and the Northern Tract, comprising 8,320 net acres, with separate options for each tract. We paid $5.0 million for the option for the Southern Tract and are currently drilling a commitment well on the Southern Tract. We have until June 15, 2017 to exercise the option on either the Southern Tract acreage or on all 15,040 net acres, in each case for $11,000 per acre. If we initially elect only to exercise our option on the Southern Tract, we would need to pay $5.0 million on or before June 15, 2017 and drill a commitment well on the Northern Tract by September 1, 2017 to earn an option to acquire the Northern Tract acreage for $11,000 per acre by December 31, 2017.

Reorganization

The prices of crude oil and natural gas declined dramatically from mid-year 2014 through 2016, reaching multi-year lows, as a result of robust non-Organization of the Petroleum Exporting Countries' (OPEC) supply growth led by unconventional production in the United States, weak demand in emerging markets, and OPEC's decision to sustain high production levels during this period. In response to these developments, among other things, in 2015 and 2016 we reduced our spending and completed a series of transactions that resulted in the reduction of our debt by approximately $1.1 billion and reduced our annual interest burden by approximately $61.5 million. We also extended the maturity date and amended other provisions of certain of our debt agreements.

These efforts proved insufficient in light of continued low commodity prices to ensure our ability to weather the current downturn or position us to take advantage of opportunities that might arise. Accordingly, on July 27, 2016, we and certain of our subsidiaries (the Halcón Entities) filed voluntary petitions for relief under chapter 11 of the United States Bankruptcy Code in the U.S. Bankruptcy Court in the District of Delaware (the Bankruptcy Court) to pursue a prepackaged plan of reorganization in accordance with the terms of the Restructuring Support Agreement discussed below. Prior to filing the chapter 11 bankruptcy petitions, on June 9, 2016, the Halcón Entities entered into a restructuring support agreement (the Restructuring Support Agreement) with certain holders of our 13% senior secured third lien notes due 2022 (the Third Lien Noteholders), our 8.875% senior unsecured notes due 2021, 9.25% senior unsecured notes due 2022 and 9.75% senior unsecured notes due 2020 (collectively, the Unsecured Noteholders), the holder of our 8% senior unsecured convertible note due 2020 (the Convertible Noteholder), and certain holders of our 5.75% Series A Convertible Perpetual Preferred Stock (the Preferred Holders), to support a restructuring in accordance with the terms of a plan of reorganization as described therein (the Plan). On September 8, 2016, the Halcón Entities received confirmation of their joint prepackaged plan of reorganization from the Bankruptcy Court and subsequently emerged from chapter 11 bankruptcy on September 9, 2016 (the Effective Date).

Upon emergence, pursuant to the terms of the Plan, the following significant transactions occurred:

- the Predecessor Credit Agreement was refinanced and replaced with the DIP Facility, which was subsequently converted into the Senior Credit Agreement (see below for credit agreement definitions and further details regarding the credit agreements);
- the Second Lien Notes (consisting of $700.0 million in aggregate principal amount outstanding of 8.625% senior secured notes due 2020 and $112.8 million in aggregate principal amount outstanding of 12% senior secured notes due 2022) were unimpaired and reinstated;
- the Third Lien Notes were cancelled and the Third Lien Noteholders received their pro rata share of 76.5% of the common stock of reorganized Halcón, together with a cash payment of $33.8 million, and accrued and unpaid interest on their notes through May 15, 2016, which was paid prior to the chapter 11 bankruptcy filing, in full and final satisfaction of their claims;
- the Unsecured Notes were cancelled and the Unsecured Noteholders received their pro rata share of 15.5% of the common stock of reorganized Halcón, together with a cash payment of $37.6 million and warrants to purchase 4% of the common stock of reorganized Halcón (with a four year term and an exercise price of $14.04 per share), and accrued and unpaid interest on their notes through May 15, 2016, which was paid prior to the chapter 11 bankruptcy filing, in full and final satisfaction of their claims;
- the Convertible Note was cancelled and the Convertible Noteholder received 4% of the common stock of reorganized Halcón, together with a cash payment of $15.0 million and warrants to

purchase 1% of the common stock of reorganized Halcón (with a four year term and an exercise price of $14.04 per share), in full and final satisfaction of their claims;

- the general unsecured claims were unimpaired and paid in full in the ordinary course;
- all outstanding shares of the preferred stock were cancelled and the Preferred Holders received their pro rata share of $11.1 million in cash, in full and final satisfaction of their interests; and
- all of the outstanding shares of common stock were cancelled and the common stockholders received their pro rata share of 4% of the common stock of reorganized Halcón, in full and final satisfaction of their interests.

Each of the foregoing percentages of equity in the reorganized company were as of September 9, 2016 and subject to dilution from the exercise of the new warrants described above, a management incentive plan and other future issuances of equity securities.

Fresh-start Accounting

Upon our emergence from chapter 11 bankruptcy, on September 9, 2016, we adopted fresh-start accounting in accordance with the provisions set forth in Accounting Standards Codification (ASC) 852, *Reorganizations,* as (i) the Reorganization Value of our assets immediately prior to the date of confirmation was less than the post-petition liabilities and allowed claims and (ii) the holders of our existing voting shares of the Predecessor entity received less than 50% of the voting shares of the emerging entity.

Adopting fresh-start accounting results in a new financial reporting entity with no beginning or ending retained earnings or deficit balances as of the fresh-start reporting date. Upon the adoption of fresh-start accounting, our assets and liabilities were recorded at their fair values as of the fresh-start reporting date. Our adoption of fresh-start accounting may materially affect our results of operations following the fresh-start reporting date, as we have a new basis in our assets and liabilities. As a result of the adoption of fresh-start reporting and the effects of the implementation of the Plan, our consolidated financial statements subsequent to September 9, 2016 are not comparable to our consolidated financial statements prior to September 9, 2016, as such, "black-line" financial statements are presented to distinguish between the Predecessor and Successor companies. Refer to *Item 8. Consolidated Financial Statements and Supplementary Data—Note 3, "Fresh-start Accounting,"* for more details.

HK TMS Divestiture

On September 30, 2016 (Successor), certain of our wholly-owned subsidiaries executed an Assignment and Assumption Agreement with an affiliate of Apollo Global Management (Apollo) pursuant to which Apollo acquired one hundred percent (100%) of the common shares (the Membership Interests) of HK TMS, LLC (HK TMS), which the transaction is referred to as the HK TMS Divestiture. HK TMS was previously a wholly-owned subsidiary of ours and held all of our oil and natural gas properties in the Tuscaloosa Marine Shale (TMS). In exchange for the assignment of the Membership Interests, Apollo assumed all obligations relating to the Membership Interests, which were previously classified as *"Mezzanine Equity"* on the consolidated balance sheets of HK TMS, from and after such date. The TMS properties generated net production of approximately 530 Boe/d during the nine months ended September 30, 2016 and had 1.1 MMBoe of proved reserves at December 31, 2015 (Predecessor).

Successor Senior Revolving Credit Facility

On the Effective Date, we entered into a senior secured revolving credit agreement (the Senior Credit Agreement) with JPMorgan Chase Bank, N.A., as administrative agent, and certain other financial institutions party thereto, as lenders, which refinanced the DIP Facility, discussed below. The Senior Credit Agreement provides for a $1.5 billion senior secured reserve-based revolving credit facility with a current borrowing base of $600.0 million. The maturity date of the Senior Credit Agreement is the earlier of (i) July 28, 2021 and (ii) the 120th day prior to the February 1, 2020 stated maturity date of our 2020 Second Lien Notes (defined below), if such notes have not been refinanced, redeemed or repaid in full on or prior to such 120th day. The first borrowing base redetermination will be on May 1, 2017 and redeterminations will occur semi-annually thereafter, with us and the lenders each having the right to one interim unscheduled redetermination between any two consecutive semi-annual redeterminations. The borrowing base takes into account the estimated value of our oil and natural gas properties, proved reserves, total indebtedness, and other relevant factors consistent with customary oil and natural gas lending criteria. Amounts outstanding under the Senior Credit Agreement bear interest at specified margins over the base rate of 1.75% to 2.75% for ABR-based loans or at specified margins over LIBOR of 2.75% to 3.75% for Eurodollar-based loans. These margins fluctuate based on our utilization of the facility. We may elect, at our option, to prepay any borrowings outstanding under the Senior Credit Agreement without premium or penalty (except with respect to any break funding payments which may be payable pursuant to the terms of the Senior Credit Agreement). Additionally, if we have outstanding borrowings or letters of credit or reimbursement obligations in respect of letters of credit and the Consolidated Cash Balance (as defined in the Senior Credit Agreement) exceeds $100.0 million as of the close of business on the most recently ended business day, we may also be required to make mandatory prepayments.

The Senior Credit Agreement also contains certain financial covenants, including the maintenance of (i) a Total Net Indebtedness Leverage Ratio (as defined in the Senior Credit Agreement) not to exceed 4.75:1.00 initially, determined as of each four fiscal quarter period and commencing with the fiscal quarter ending September 30, 2016, stepping down to 4.50:1.00 and 4.00:1.00 on September 30, 2017 and March 31, 2019, respectively, and (ii) a Current Ratio (as defined in the Senior Credit Agreement) not to be less than 1.00:1.00, commencing with the fiscal quarter ending December 31, 2016.

DIP Facility

In connection with the chapter 11 bankruptcy proceedings, we entered into a commitment letter pursuant to which the lenders party thereto committed to provide, subject to certain conditions, a $600.0 million debtor-in-possession senior secured, super-priority revolving credit facility (the DIP Facility) and to replace it upon emergence with a $600.0 million senior secured reserve-based revolving credit facility, discussed above. Proceeds from the DIP Facility were used to refinance borrowings under our Predecessor Credit Agreement. Availability under the DIP Facility was $500.0 million upon interim approval by the Bankruptcy Court, and rose to $600.0 million upon entry of a final order. The DIP Facility was refinanced by the Senior Credit Agreement on the Effective Date. Loans under the DIP Facility bore interest at specified margins over the base rate of 1.75% to 2.75% for ABR-based loans or at specified margins over LIBOR of 2.75% to 3.75% for Eurodollar-based loans. These margins fluctuated based on the utilization of the DIP Facility.

Capital Resources and Liquidity

Our near-term capital spending requirements are expected to be funded with cash flows from operations and borrowings under our Senior Credit Agreement, the terms of which are discussed above.

The Senior Credit Agreement contains certain financial covenants, including the maintenance of (i) a Total Net Indebtedness Leverage Ratio (as defined in the Senior Credit Agreement) not to exceed 4.75:1.00 initially, determined as of each four fiscal quarter period and commencing with the fiscal quarter ending September 30, 2016, stepping down to 4.50:1.00 and 4.00:1.00 on September 30, 2017 and March 31, 2019, respectively, and (ii) a Current Ratio (as defined in the Senior Credit Agreement) not to be less than 1.00:1.00, commencing with the fiscal quarter ending December 31, 2016. At December 31, 2016, we had approximately $186.0 million of indebtedness outstanding, $6.7 million letters of credit outstanding and approximately $407.3 million of borrowing capacity available under our Senior Credit Agreement. At December 31, 2016, we were in compliance with the financial covenants under the Senior Credit Agreement.

We have in the past obtained amendments to the covenants under our financing agreements under circumstances where we anticipated that it might be challenging for us to comply with our financial covenants for a particular period of time. For example, under the Predecessor Credit Agreement, we received a reduction in the minimum required interest coverage ratio of 2.0 to 1.0 on March 21, 2014 and again on February 25, 2015. The basis for these amendment and waiver requests was the potential for us to fall out of compliance as a result of our strategic decisions. Declining commodity prices also adversely impacted our ability to comply with these covenants. As part of our plan to manage liquidity risks, we scaled back our capital expenditures budget, focused our drilling program on our highest return projects, continued to explore opportunities to divest non-core properties and completed our reorganization (as described above). Upon consummation of the Plan and emergence from chapter 11 bankruptcy, approximately $2.0 billion of our debt obligations were cancelled, reducing our ongoing interest obligations by more than $200 million annually.

In the event that we are unable to access sufficient capital to fund our business and planned capital expenditures, we may be required to further curtail our drilling, development, land acquisition and other activities, which could result in a decrease in our production of oil and natural gas, subject us to forfeitures of leasehold interests to the extent we are unable or unwilling to renew them, and force us to sell some of our assets on an untimely or unfavorable basis, each of which could adversely affect our results of operations and financial condition.

Our future capital resources and liquidity depend, in part, on our success in developing our leasehold interests, growing reserves and production and finding additional reserves. Cash is required to fund capital expenditures necessary to offset inherent declines in our production and proved reserves, which is typical in the capital-intensive oil and natural gas industry. We therefore continuously monitor our liquidity and the capital markets and evaluate our development plans in light of a variety of factors, including, but not limited to, our cash flows, capital resources, acquisition opportunities and drilling successes.

We strive to maintain financial flexibility while pursuing our drilling plans and evaluating potential acquisitions, and will therefore likely continue to access capital markets (if on acceptable terms) as necessary to, among other things, maintain substantial borrowing capacity under our Senior Credit Agreement, facilitate drilling on our large undeveloped acreage position and permit us to selectively expand our acreage position and infrastructure projects while sustaining sufficient operating cash levels. Our ability to complete future debt and equity offerings and maintain or increase our borrowing base is subject to a number of variables, including our level of oil and natural gas production, reserves and commodity prices, as well as various economic and market conditions that have historically affected the oil and natural gas industry. Even if we are otherwise successful in growing our reserves and production, if oil and natural gas prices decline for a sustained period of time, our ability to fund our capital expenditures, complete acquisitions, reduce debt, meet our financial obligations and become profitable may be materially impacted.

We are exposed to various risks including energy commodity price risk. When oil, natural gas, and natural gas liquids prices decline significantly, as they have since mid-year 2014, our ability to finance our capital budget and operations may be adversely impacted. While we use derivative instruments to provide partial protection against declines in oil and natural gas prices, the total volumes we hedge varies from period to period based on our view of current and future market conditions. Our hedge policies and objectives may change significantly as our operational profile changes and/or commodities prices change. We do not enter into derivative contracts for speculative trading purposes.

Cash Flow

Historically, our primary sources of cash were from operating and financing activities. For the period of January 1, 2016 through September 9, 2016 (Predecessor), cash generated by operating and financing activities was used to fund our drilling and completion program and to support our reorganization plan. For the period of September 10, 2016 through December 31, 2016 (Successor), cash generated by operating activities was used to fund our drilling and completion program and make repayments on our Senior Credit Agreement. See "Results of Operations" for a review of the impact of prices and volumes on sales. The period of September 10, 2016 through December 31, 2016 (Successor) and the period of January 1, 2016 through September 9, 2016 (Predecessor) are distinct reporting periods as a result of our emergence from chapter 11 bankruptcy on September 9, 2016 and are not comparable to prior periods.

Net increase (decrease) in cash is summarized as follows (in thousands):

	Successor	Predecessor		
	Period from September 10, 2016 through December 31, 2016	Period from January 1, 2016 through September 9, 2016	Years Ended December 31, 2015	2014
Cash flows provided by (used in) operating activities	$103,136	$ 175,348	$ 466,999	$ 667,934
Cash flows provided by (used in) investing activities	(63,042)	(227,774)	(667,132)	(1,271,093)
Cash flows provided by (used in) financing activities	(54,013)	58,343	164,446	644,038
Net increase (decrease) in cash	$(13,919)	$ 5,917	$ (35,687)	$ 40,879

Operating Activities. Net cash provided by operating activities for the period of September 10, 2016 through December 31, 2016 (Successor) and the period of January 1, 2016 through September 9, 2016 (Predecessor) were $103.1 million and $175.3 million, respectively. Net cash provided by operating activities were $467.0 million and $667.9 million for the years ended December 31, 2015 and 2014 (Predecessor), respectively. Key drivers of net operating cash flows are commodity prices, production volumes, operating costs, and in 2016 and 2015, realized settlements on our derivative contracts.

For the period September 10, 2016 through December 31, 2016 (Successor), cash flows were modestly impacted by changes in our working capital. For the period January 1, 2016 through September 9, 2016 (Predecessor) our net operating cash flows were $175.3 million, which resulted primarily from realized settlements on our derivative contracts that were partially offset by transaction costs related to our chapter 11 bankruptcy and reorganization activities.

For the year ended December 31, 2015, the $467.0 million of net cash provided by operating activities primarily reflects the impact of realized settlements on our derivative contracts of $418.4 million, which largely mitigated the decrease in revenues due to lower commodity prices, as compared to the prior year period. Cash operating expenses also decreased over the prior year period.

For the year ended December 31, 2014, net cash provided by operating activities increased $174.0 million over the prior year. The improvement in operating cash flows primarily reflects the impact of the 26% increase in our average daily production compared to the 2013 period, which drove the increase in operating revenues. Production for 2014 averaged 42,107 Boe/d compared to 33,329 Boe/d in 2013.

Investing Activities. The primary driver of cash used in investing activities is capital spending on our oil and natural gas properties. Net cash used in investing activities for the period of September 10, 2016 through December 31, 2016 (Successor) and the period of January 1, 2016 through September 9, 2016 (Predecessor) were $63.0 million and $227.8 million, respectively. Net cash used in investing activities was $667.1 million and $1.3 billion for the years ended December 31, 2015 and 2014 (Predecessor), respectively.

During the period of September 10, 2016 through December 31, 2016 (Successor), we spent $61.5 million on oil and natural gas capital expenditures, of which $54.4 million related to drilling and completion costs. During the period of January 1, 2016 through September 9, 2016 (Predecessor), we spent $226.6 million on oil and natural gas capital expenditures, of which $129.5 million related to drilling and completion costs and the remainder was primarily associated with capitalized interest, and to a lesser extent, leasing and seismic data. In 2016 (for the combined Successor and Predecessor periods), we participated in the drilling of 90 gross (30.6 net) wells, all of which were completed and capable of production.

In 2015, we used $659.4 million of cash on oil and natural gas capital expenditures, of which $508.4 million related to drilling and completion costs and the remainder was primarily associated with capitalized interest, leasing and seismic data. We participated in the drilling of 184 gross (49.0 net) wells, all of which were completed and capable of production. We significantly decreased our capital spending for 2015, as compared to capital expenditure levels in prior years, in response to the significant decrease in crude oil prices over the latter of 2014 and throughout 2015, and our expectation that prices may not recover in the near term. Cash paid for drilling and completion costs during the year were attributable to both costs incurred before we slowed our drilling and completion program and costs related to wells spud or drilled during the period.

In 2014, we used $1.5 billion of cash on oil and natural gas capital expenditures, of which $1.2 billion related to drilling and completion costs and the remainder was primarily associated with leasing, acquisitions and seismic data. We participated in the drilling of 320 gross (98.3 net) wells, all of which were completed and capable of production. These expenditures were offset by $484.2 million in proceeds received from the divestitures of various non-core assets, including the East Texas Assets. As part of HK TMS's transaction with Apollo, discussed in further detail below, we received proceeds of approximately $33.8 million from the conveyance of an overriding royalty interest to Apollo.

Financing Activities. Net cash flows used in financing activities for the period of September 10, 2016 through December 31, 2016 (Successor) were $54.0 million and net cash flows provided by financing activities for the period of January 1, 2016 through September 9, 2016 (Predecessor) were $58.3 million. Net cash flows provided by financing activities were $164.4 million and $644.0 million for the years ended December 31, 2015 and 2014 (Predecessor), respectively.

During the period of September 10, 2016 through December 31, 2016 (Successor), we paid a consent fee of approximately $10.0 million to holders of our Second Lien Notes and made net repayments of $44.0 million on our Senior Credit Agreement. The primary drivers of cash provided by financing activities for the period of January 1, 2016 through September 9, 2016 (Predecessor) were net borrowings on our Predecessor Credit Agreement, offset by cash payments totaling $97.5 million made to the Third Lien Noteholders, Unsecured Noteholders, Convertible Noteholder and Preferred Holders in accordance with the Plan.

During the first quarter of 2016 (Predecessor), we repurchased approximately $24.5 million principal amount of our 9.75% senior notes due 2020, $51.8 million principal amount of our 8.875% senior notes due 2021, and $15.5 million principal amount of our 9.25% senior notes due 2022. The net cash used to make these repurchases was approximately $9.7 million and we recognized an $81.4 million net gain on the extinguishment of debt, as an $82.1 million gain on the repurchase was partially offset by the write-down of $0.7 million associated with related issuance costs and discounts and premiums for the respective senior unsecured notes. Upon settlement of the repurchases, we paid all accrued and unpaid interest since the respective interest payment dates of the senior unsecured notes repurchased.

During the fourth quarter of 2015 (Predecessor), we repurchased approximately $6.2 million principal amount of our 9.75% senior notes due 2020, $28.0 million principal amount of our 8.875% senior notes due 2021, and $10.3 million principal amount of our 9.25% senior notes due 2022. The net cash used to make these repurchases was approximately $14.8 million and we recognized a $29.4 million net gain on the extinguishment of debt, as a $29.7 million gain on the repurchase was partially offset by the write-down of $0.3 million associated with related issuance costs and discounts and premiums for the respective unsecured notes. Upon settlement of the repurchases, we paid all accrued and unpaid interest since the respective interest payment dates of the notes repurchased.

On May 1, 2015 (Predecessor), we completed the issuance of $700.0 million aggregate principal amount of our 2020 Second Lien Notes. The net proceeds from the offering were approximately $686.2 million after deducting commissions and offering expenses and were used to repay a majority of the then outstanding borrowings under our Predecessor Credit Agreement.

Cash flows provided by financing activities include net borrowings under our Predecessor Credit Agreement of $62.0 million for the year ended December 31, 2015 (Predecessor), primarily used to fund drilling and completion activities and other general corporate purposes.

During the year ended December 31, 2015, cash flows from financing activities were modestly impacted by sales of our Predecessor common stock. For the year ended December 31, 2015 (Predecessor), we sold approximately 1.9 million shares for net proceeds of approximately $15.0 million, after deducting offering expenses.

On June 16, 2014 (Predecessor), our subsidiary, HK TMS, entered into a transaction with Apollo by initially selling 150,000 preferred shares in HK TMS, which held all of our acreage in the TMS, located in Mississippi and Louisiana. Apollo contributed $150 million to HK TMS, and we contributed all our assets related to the TMS as well as $50 million in cash. The proceeds from Apollo were allocated as follows: $110.1 million of proceeds associated with the issuance of HK TMS preferred stock and approximately $4.5 million associated with Apollo's rights to additional preferred shares within cash flows from financing activities and the aforementioned $33.8 million investing cash flows related to the overriding royalty conveyance. The proceeds were used to develop the TMS.

Contractual Obligations

We have a significant degree of flexibility to adjust the level of our future capital expenditures as circumstances warrant. Our level of capital expenditures will vary in future periods depending on the success we experience in our acquisition, developmental and exploration activities, oil and natural gas price conditions, our access to capital and liquidity and other related economic factors. We currently have no material off-balance sheet arrangements or transactions with unconsolidated, limited-purpose entities. The following table summarizes our contractual obligations and commitments by payment periods as of December 31, 2016 (Successor).

Contractual Obligations	Payments Due by Period Total	2017	2018 - 2019	2020 - 2021	2022 and Beyond
			(In thousands)		
Successor senior revolving credit facility	$ 186,000	$ —	$186,000	$ —	$ —
8.625% senior secured second lien notes due 2020[(1)(2)]	700,000	—	—	700,000	—
12.0% senior secured second lien notes due 2022[(3)]	112,826	—	—	—	112,826
Interest expense on long-term debt[(4)]	280,314	82,906	163,644	32,109	1,655
Operating leases	15,518	3,493	6,537	3,308	2,180
Drilling rig commitments	25,018	17,574	7,444	—	—
Rig stacking commitments	11,080	6,820	1,260	3,000	—
Total contractual obligations	$1,330,756	$110,793	$364,885	$738,417	$116,661

(1) *Excludes a $27.4 million unamortized discount.*

(2) *On February 16, 2017, we issued $850.0 million aggregate principal amount of new 6.75% senior unsecured notes due 2025. We utilized a portion of the net proceeds from the issuance of the new 6.75% senior unsecured notes to repurchase approximately $289.2 million aggregate principal amount of the 2020 Second Lien Notes and will use the remaining net proceeds to redeem the remaining $410.8 million aggregate principal amount of 2020 Second Lien Notes and for general corporate purposes. These transactions are not included in the table above. See "6.75% Senior Notes" below and Item 8. Consolidated Financial Statements and Supplementary Data-Note 17, "Subsequent Events," for more details.*

(3) *Excludes a $6.8 million unamortized discount.*

(4) *Future interest expense was calculated based on interest rates and debt amounts outstanding at December 31, 2016 less required annual repayments.*

We lease corporate office space in Houston, Texas and Denver, Colorado as well as a number of other field office locations. Rent expense was approximately $1.4 million for the period of September 10, 2016 through December 31, 2016 (Successor) and $5.9 million for the period January 1, 2016 through September 30, 2016 (Predecessor). Rent expense was approximately $8.6 million and $8.1 million for the years ended December 31, 2015 and 2014 (Predecessor), respectively. In connection with the chapter 11 bankruptcy, we modified and rejected certain office lease arrangements and paid approximately $3.4 million for these modifications and rejections subsequent to the emergence from chapter 11 bankruptcy. Future obligations associated with our operating leases are presented in the table above.

On December 9, 2016, we entered into an agreement with a private operator for the right to purchase the Ward County Assets. The Ward County Assets are divided into two tracts: the Southern Tract (6,720 net acres) and the Northern Tract (8,320 net acres) with separate options for each tract. Pursuant to the terms of the agreement, in January 2017, we paid $5.0 million and began drilling a commitment well on the Southern Tract. We have until June 15, 2017 to exercise the option on either the Southern Tract acreage or on all 15,040 net acres, in each case for $11,000 per acre. If we initially elect only to exercise our option on the Southern Tract, we would need to pay $5.0 million on or before June 15, 2017 and drill a commitment well on the Northern Tract by September 1, 2017 to earn an option to acquire the Northern Tract acreage for $11,000 per acre by December 31, 2017. This option purchase is not included in the table above.

We also have various long-term gathering, transportation and sales contracts in the Bakken / Three Forks formations in North Dakota that are not included in the table above. As of December 31, 2016 (Successor), we had in place eight long-term crude oil contracts and five long-term natural gas contracts in this area, with sales prices based on posted market rates. Under the terms of these contracts we have committed a substantial portion of our Bakken/Three Forks production for periods ranging from one to ten years from the date of first production. We believe that there are sufficient available reserves and production in the Bakken/Three Forks formations to meet our commitments, as the proved reserves from this area represent approximately 76% of our total proved reserves. Historically, we have been able to meet our delivery commitments.

The contractual obligations table does not include obligations to taxing authorities due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations. In addition, amounts related to our asset retirement obligations are not included in the table above given the uncertainty regarding the actual timing of such expenditures. The total estimated amount of our asset retirement obligations at December 31, 2016 (Successor) was $32.4 million.

Successor Senior Revolving Credit Facility

On the Effective Date, we entered into a senior secured revolving credit agreement with JPMorgan Chase Bank, N.A., as administrative agent, and certain other financial institutions party thereto, as lenders, which refinanced the DIP facility, discussed below. The Senior Credit Agreement provides for a $1.5 billion senior secured reserve-based revolving credit facility with a current borrowing base of $600.0 million. The maturity date of the Senior Credit Agreement is the earlier of (i) July 28, 2021 and (ii) the 120th day prior to the February 1, 2020 stated maturity date of our 2020 Second Lien Notes (defined below), if such notes have not been refinanced, redeemed or repaid in full on or prior to such 120th day. The first borrowing base redetermination will be on May 1, 2017 and redeterminations will occur semi-annually thereafter, with the lenders and us each having the right to one interim unscheduled redetermination between any two consecutive semi-annual redeterminations. The borrowing base takes into account the estimated value of our oil and natural gas properties, proved reserves, total indebtedness, and other relevant factors consistent with customary oil and natural gas lending criteria. Amounts outstanding under the Senior Credit Agreement bear interest at specified margins over the base rate of 1.75% to 2.75% for ABR-based loans or at specified margins over LIBOR of 2.75% to 3.75% for Eurodollar-based loans. These margins fluctuate based on the utilization of the facility. We may elect, at our option, to prepay any borrowings outstanding under the Senior Credit Agreement without premium or penalty (except with respect to any break funding payments which may be payable pursuant to the terms of the Senior Credit Agreement). Additionally, if we have outstanding borrowings or letters of credit or reimbursement obligations in respect of letters of credit and the Consolidated Cash Balance (as defined in the Senior Credit Agreement) exceeds $100.0 million as of the close of business on the most recently ended business day, we may also be required to make mandatory prepayments.

Amounts outstanding under the Senior Credit Agreement are guaranteed by certain of our direct and indirect subsidiaries and secured by a security interest in substantially all of the assets of us and our subsidiaries.

The Senior Credit Agreement also contains certain financial covenants, including the maintenance of (i) a Total Net Indebtedness Leverage Ratio (as defined in the Senior Credit Agreement) not to exceed 4.75:1.00 initially, determined as of each four fiscal quarter periods and commencing with the fiscal quarter ending September 30, 2016, stepping down to 4.50:1.00 and 4.00:1.00 on September 30, 2017 and March 31, 2019, respectively, and (ii) a Current Ratio (as defined in the Senior Credit Agreement) not to be less than 1.00:1.00, commencing with the fiscal quarter ending December 31, 2016. At December 31, 2016, we were in compliance with the financial covenants under the Senior Credit Agreement.

The Senior Credit Agreement also contains certain events of default, including non-payment; breaches of representations and warranties; non-compliance with covenants or other agreements; cross-default to material indebtedness; judgments; change of control; and voluntary and involuntary bankruptcy.

At December 31, 2016, we had approximately $186.0 million of indebtedness outstanding, approximately $6.7 million letters of credit outstanding and approximately $407.3 million of borrowing capacity available under the Senior Credit Agreement.

8.625% Senior Secured Second Lien Notes

On May 1, 2015 (Predecessor), we issued $700.0 million aggregate principal amount of our 8.625% senior secured second lien notes due 2020 (the 2020 Second Lien Notes) in a private placement. The 2020 Second Lien Notes were issued at par. The net proceeds from the sale of the 2020 Second Lien Notes were approximately $686.2 million (after deducting offering fees and expenses).

The 2020 Second Lien Notes bear interest at a rate of 8.625% per annum, payable semi-annually on February 1 and August 1 of each year. The 2020 Second Lien Notes will mature on February 1, 2020. The 2020 Second Lien Notes are secured by second-priority liens on substantially all of our and our subsidiaries' assets to the extent such assets secure our Senior Credit Agreement and our 2022 Second Lien Notes (defined below) (the Collateral). Pursuant to the terms of an Intercreditor Agreement, dated May 1, 2015, as amended by those certain Priority Confirmation Joinders, dated September 10, 2015 and December 21, 2015, in connection with the issuance of the Third Lien Notes and the 2022 Second Lien Notes (discussed below), respectively (the Intercreditor Agreement), the security interest in those assets that secure the 2020 Second Lien Notes and the guarantees are contractually subordinated to liens that secure the Senior Credit Agreement and certain other permitted indebtedness. Consequently, the 2020 Second Lien Notes and the guarantees are effectively subordinated to the Senior Credit Agreement and such other indebtedness to the extent of the value of such assets. The Collateral does not include any of the assets of our future unrestricted subsidiaries. In accordance with the terms of the Plan, the 2020 Second Lien Notes were unimpaired and reinstated upon our emergence from the chapter 11 bankruptcy.

On September 9, 2016, in connection with fresh-start accounting, we adjusted the 2020 Second Lien Notes to fair value of $679.0 million by recording a discount of $21.0 million to be amortized over the remaining life of the 2020 Second Lien Notes, using the effective interest method.

In addition, on September 28, 2016 (Successor), us and each of our guarantors and U.S. Bank National Association, as trustee, entered into a supplemental indenture (the 2020 Second Lien Note Supplemental Indenture) to the Indenture dated as of May 1, 2015 with respect to the 2020 Second Lien Notes (the 2020 Second Lien Note Indenture). The 2020 Second Lien Note Supplemental Indenture amended the 2020 Second Lien Note Indenture to modify the incurrence of indebtedness, lien and restricted payments covenants. The 2020 Second Lien Note Supplemental Indenture became operative upon the consummation of the consent solicitation on September 30, 2016 (Successor). We paid an aggregate consent fee of approximately $8.6 million to holders of the 2020 Second Lien Notes and recorded an additional discount of approximately $8.6 million. The remaining unamortized discount was $27.4 million at December 31, 2016.

On February 16, 2017 (Successor), we paid approximately $303.5 million for approximately $289.2 million principal amount of 2020 Second Lien Notes, a make-whole premium of $13.2 million plus accrued and unpaid interest of approximately $1.1 million to repurchase such notes pursuant to a tender offer and issued a redemption notice to redeem the remaining 2020 Second Lien Notes. The remaining $410.8 million aggregate principal amount of 2020 Second Lien Notes will be repurchased through the guaranteed delivery procedures or redeemed at a price of 104.313% of the principal amount thereof, plus accrued and unpaid interest to, but not including, the redemption date. The redemption date is expected to be March 20, 2017. The repurchase and redemption of the 2020 Second

Lien Notes will be funded with proceeds from the issuance of $850.0 million in new 6.75% senior unsecured notes due 2025. See *"Recent Developments"* for further details.

12.0% Senior Secured Second Lien Notes

On December 21, 2015 (Predecessor), we completed the issuance in a private placement of approximately $112.8 million aggregate principal amount of new 12.0% senior secured second lien notes due 2022 (the 2022 Second Lien Notes) in exchange for approximately $289.6 million principal amount of our then outstanding senior unsecured notes, consisting of $116.6 million principal amount of 9.75% senior notes due 2020, $137.7 million principal amount of 8.875% senior notes due 2021 and $35.3 million principal amount of 9.25% senior notes due 2022. At closing, we paid all accrued and unpaid interest since the respective interest payment dates of the unsecured notes surrendered in the exchange. We recorded the issuance of the 2022 Second Lien Notes at par.

Interest on the 2022 Second Lien Notes accrues at a rate of 12.0% per annum, payable semi-annually on February 15 and August 15 of each year. The 2022 Second Lien Notes will mature on February 15, 2022. The 2022 Second Lien Notes are secured by second-priority liens on the Collateral. Pursuant to the terms of the Intercreditor Agreement, dated December 21, 2015, the security interest in the Collateral securing the 2022 Second Lien Notes and the guarantees are contractually equal with the liens that secure the 2020 Second Lien Notes and contractually subordinated to liens that secure the Senior Credit Agreement and certain other permitted indebtedness. Consequently, the 2022 Second Lien Notes and the guarantees are effectively subordinated to the Senior Credit Agreement and such other indebtedness and effectively equal to the 2020 Second Lien Notes, in each case to the extent of the value of the Collateral. In accordance with the terms of the Plan, the 2022 Second Lien Notes were unimpaired and reinstated upon our emergence from chapter 11 bankruptcy.

On September 9, 2016, in connection with fresh-start accounting, we adjusted the 2022 Second Lien Notes to fair value of $107.2 million by recording a discount of $5.7 million to be amortized over the remaining life of the 2022 Second Lien Notes, using the effective interest method.

In addition, on September 28, 2016 (Successor), us and each of our guarantors and U.S. Bank National Association, as trustee, entered into a supplemental indenture (the 2022 Second Lien Note Supplemental Indenture) to the Indenture dated as of December 21, 2015 with respect to the 2022 Second Lien Notes (the 2022 Second Lien Note Indenture). The 2022 Second Lien Note Supplemental Indenture amended the 2022 Second Lien Note Indenture to modify the incurrence of indebtedness, lien and restricted payments covenants. The 2022 Second Lien Note Supplemental Indenture became operative upon the consummation of the consent solicitation on September 30, 2016 (Successor). We paid an aggregate consent fee of approximately $1.4 million to holders of the 2022 Second Lien Notes and recorded an additional discount of approximately $1.4 million.

The remaining unamortized discount was $6.8 million at December 31, 2016.

Off-Balance Sheet Arrangements

At December 31, 2016 (Successor), we did not have any material off-balance sheet arrangements.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our consolidated financial statements requires us to make estimates and assumptions that affect our reported results of operations and the amount of reported assets, liabilities and proved oil and natural gas reserves. Some accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. Actual results may differ from the estimates and assumptions used in the preparation of our consolidated financial statements. Described below are the most significant policies we apply in preparing our consolidated financial statements, some of which are subject to alternative treatments under accounting principles generally accepted in the United States. We also describe the most significant estimates and assumptions we make in applying these policies. We discussed the development, selection and disclosure of each of these with our audit committee. See Item 8. *Consolidated Financial Statements and Supplementary Data*—Note 1, "*Summary of Significant Events and Accounting Policies,"* for a discussion of additional accounting policies and estimates made by management.

Fresh-start Accounting

Upon our emergence from chapter 11 bankruptcy, on September 9, 2016, we adopted fresh-start accounting in accordance with the provisions set forth in ASC 852, *Reorganizations,* as (i) the Reorganization Value of our assets immediately prior to the date of confirmation was less than the post-petition liabilities and allowed claims and (ii) the holders of our existing voting shares of the Predecessor entity received less than 50% of the voting shares of the emerging entity. Adopting fresh-start accounting results in a new financial reporting entity with no beginning or ending retained earnings or deficit balances. Upon the adoption of fresh-start accounting, our assets and liabilities were recorded at their fair values as of the fresh-start reporting date.

Fresh-start accounting requires an entity to present its assets, liabilities, and equity as if it were a new entity upon emergence from bankruptcy. The new entity is referred to as "Successor" or "Successor Company." However, we will continue to present financial information for any periods before adoption of fresh-start accounting for the Predecessor Company. The Predecessor and Successor companies may lack comparability, as required in ASC Topic 205, *Presentation of Financial Statements* (ASC 205). ASC 205 states financial statements are required to be presented comparably from year to year, with any exceptions to comparability clearly disclosed. Therefore, "black-line" financial statements are presented to distinguish between the Predecessor and Successor Companies. Refer to Item 1. *Condensed Consolidated Financial Statements (Unaudited)*—Note 3, *"Fresh-start Accounting,"* for further details.

Oil and Natural Gas Activities

Accounting for oil and natural gas activities is subject to unique rules. Two generally accepted methods of accounting for oil and natural gas activities are available—successful efforts and full cost. The most significant differences between these two methods are the treatment of unsuccessful exploration costs and the manner in which the carrying value of oil and natural gas properties are amortized and evaluated for impairment. The successful efforts method requires unsuccessful exploration costs to be expensed as they are incurred upon a determination that the well is uneconomical while the full cost method provides for the capitalization of these costs. Both methods generally provide for the periodic amortization of capitalized costs based on proved reserve quantities. Impairment of oil and natural gas properties under the successful efforts method is based on an evaluation of the carrying value of individual oil and natural gas properties against their estimated fair value, while impairment under the full cost method requires an evaluation of the carrying value of oil and natural gas properties included in a cost center against the net present value of future cash flows from the related proved reserves, using the unweighted arithmetic average of the first day of the month for each of the 12-month prices for oil and natural gas within the period, holding prices and costs constant and applying a 10% discount rate.

Full Cost Method

We used the full cost method of accounting for our oil and natural gas activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and natural gas properties are capitalized into a cost center (the amortization base or full cost pool). Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs and delay rentals. All general and administrative costs unrelated to drilling activities are expensed as incurred. The capitalized costs of our evaluated oil and natural gas properties, plus an estimate of our future development and abandonment costs are amortized on a unit-of-production method based on our estimate of total proved reserves. Our financial position and results of operations could have been significantly different had we used the successful efforts method of accounting for our oil and natural gas activities.

Proved Oil and Natural Gas Reserves

Estimates of our proved reserves included in this report are prepared in accordance with accounting principles generally accepted in the United States and SEC guidelines. Our engineering estimates of proved oil and natural gas reserves directly impact financial accounting estimates, including depletion, depreciation and accretion expense and the full cost ceiling test limitation. Proved oil and natural gas reserves are the estimated quantities of oil and natural gas reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under defined economic and operating conditions. The process of estimating quantities of proved reserves is very complex, requiring significant subjective decisions in the evaluation of all geological, engineering and economic data for each reservoir. The accuracy of a reserve estimate is a function of: (i) the quality and quantity of available data; (ii) the interpretation of that data; (iii) the accuracy of various mandated economic assumptions; and (iv) the judgment of the persons preparing the estimate. The data for a given reservoir may change substantially over time as a result of numerous factors, including additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Changes in oil and natural gas prices, operating costs and expected performance from a given reservoir also will result in revisions to the amount of our estimated proved reserves.

Our estimated proved reserves for the years ended December 31, 2016 (Successor), 2015 and 2014 (Predecessor) were prepared by Netherland, Sewell, an independent oil and natural gas reservoir engineering consulting firm. For more information regarding reserve estimation, including historical reserve revisions, refer to Item 8. *Consolidated Financial Statements and Supplementary Data— "Supplemental Oil and Gas Information (Unaudited).*"

Depreciation, Depletion and Accretion

Our rate of recording depletion, depreciation and accretion expense (DD&A) is primarily dependent upon our estimate of proved reserves, which is utilized in our unit-of-production method calculation. If the estimates of proved reserves were to be reduced, the rate at which we record DD&A expense would increase, reducing net income. Such a reduction in reserves may result from calculated lower market prices, which may make it non-economic to drill for and produce higher cost reserves. At December 31, 2016 (Successor), a five percent positive revision to proved reserves would decrease the DD&A rate by approximately $0.48 per Boe and a five percent negative revision to proved reserves would increase the DD&A rate by approximately $0.52 per Boe.

Full Cost Ceiling Test Limitation

Under the full cost method, we are subject to quarterly calculations of a ceiling or limitation on the amount of our oil and natural gas properties that can be capitalized on our balance sheet. If the net capitalized costs of our oil and natural gas properties exceed the cost center ceiling, we are subject to a ceiling test write down to the extent of such excess. If required, it would reduce earnings and impact stockholders' equity in the period of occurrence and result in lower amortization expense in future periods. The discounted present value of our proved reserves is a major component of the ceiling calculation and represents the component that requires the most subjective judgments. However, the associated prices of oil and natural gas reserves that are included in the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that we use the unweighted arithmetic average price of oil and natural gas as of the first day of each month for the 12-month period ending at the balance sheet date. If average oil and natural gas prices decline, or if we have downward revisions to our estimated proved reserves, it is possible that write downs of our oil and natural gas properties could occur in the future.

If the unweighted arithmetic average price of oil and natural gas as of the first day of each month for the 12-month period ended December 31, 2016 (Successor) had been 10% lower while all other factors remained constant, our ceiling amount related to our net book value of oil and natural gas properties would have been reduced by approximately $238.4 million and would have generated a full cost ceiling impairment.

Future Development Costs

Future development costs include costs incurred to obtain access to proved reserves such as drilling costs and the installation of production equipment. Future abandonment costs include costs to dismantle and relocate or dispose of our production facilities, gathering systems and related structures and restoration costs. We develop estimates of these costs for each of our properties based upon their geographic location, type of production structure, well depth, currently available procedures and ongoing consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. We review our assumptions and estimates of future development and future abandonment costs on an annual basis. At December 31, 2016 (Successor), a five percent increase in future development and abandonment costs would increase the DD&A rate by approximately $0.23 per Boe and a five percent decrease in future development and abandonment costs would decrease the DD&A rate by $0.24 per Boe.

Accounting for Derivative Instruments and Hedging Activities

We account for our derivative activities under the provisions of ASC 815, *Derivatives and Hedging* (ASC 815). ASC 815 establishes accounting and reporting that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at fair value. From time to time, when derivative contracts are available at terms (or prices) acceptable to us, we may hedge a portion of our forecasted oil, natural gas, and natural gas liquids production. Derivative contracts entered into by us have consisted of transactions in which we hedge the variability of cash flow related to a forecasted transaction. We elected to not designate any of our positions for hedge accounting. Accordingly, we record the net change in the mark-to-market valuation of these positions, as well as payments and receipts on settled contracts, in *"Net gain (loss) on derivative contracts"* on the consolidated statements of operations.

Income Taxes

Our provision for taxes includes both state and federal taxes. We account for income taxes using the asset and liability method wherein deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax assets will not be realized.

In assessing the need for a valuation allowance on our deferred tax assets, we consider possible sources of taxable income that may be available to realize the benefit of deferred tax assets, including projected future taxable income, the reversal of existing temporary differences, taxable income in carryback years and available tax planning strategies. We consider all available evidence (both positive and negative) in determining whether a valuation allowance is required. A significant item of objective negative evidence considered was the cumulative book loss over the three-year period ended December 31, 2016 (Successor) driven primarily by the full cost ceiling impairments over that period which limits the ability to consider other subjective evidence such as the Company's anticipated future growth. Based upon the evaluation of the available evidence we recorded an increase of $60.4 million to our valuation allowance resulting in a valuation allowance of $821.9 million being applied against our deferred tax assets as of December 31, 2016 (Successor).

We follow ASC 740, *Income Taxes* (ASC 740). ASC 740 creates a single model to address accounting for the uncertainty in income tax positions and prescribes a minimum recognition threshold a tax position must meet before recognition in the financial statements. We apply significant judgment in evaluating our tax positions and estimating our provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The actual outcome of these future tax consequences could differ significantly from these estimates, which could impact our financial position, results of operations and cash flows. The evaluation of a tax position in accordance with ASC 740 is a two-step process. The first step is a recognition process to determine whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. In evaluating whether a tax position has met the more likely than not recognition threshold, it is presumed that the position will be examined by the appropriate taxing authority with full knowledge of all relevant information. The second step is a measurement process whereby a tax position that meets the more likely than not recognition threshold is calculated to determine the amount of benefit/expense to recognize in the financial statements. The tax position is measured at the largest amount of benefit/expense that is more likely than not of being realized upon ultimate settlement.

In November 2015, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2015-17, *Balance Sheet Classification of Deferred Taxes* (ASU 2015-17) to simplify the presentation of deferred income taxes. Under ASU 2015-17, all deferred tax assets and liabilities, along with any related valuation allowance, are required to be classified as noncurrent on the balance sheet. Effective December 31, 2015, we early adopted ASU 2015-17, on a prospective basis, which resulted in the reclassification of our current deferred tax assets and liabilities as a non-current deferred tax assets and liabilities, net of the valuation allowance, on our consolidated balance sheets. No prior periods were retrospectively adjusted.

Comparison of Results of Operations

Year Ended December 31, 2016 (Successor) Compared to Year Ended December 31, 2015 (Predecessor)

The table included below sets forth financial information for the periods presented. The period of September 10, 2016 through December 31, 2016 (Successor) and the period of January 1, 2016 through September 9, 2016 (Predecessor) are distinct reporting periods as a result of our application of fresh-start accounting upon our emergence from chapter 11 bankruptcy on September 9, 2016 and are not comparable to prior periods. Refer to the paragraphs following the table below for a discussion around our results of operations.

In thousands (except per unit and per Boe amounts)	Successor: Period from September 10, 2016 through December 31, 2016	Predecessor: Period from January 1, 2016 through September 9, 2016	Predecessor: Year Ended December 31, 2015
Net income (loss)	$(479,193)	$ 11,958	$(1,922,621)
Operating revenues:			
Oil	139,786	248,064	512,346
Natural gas	6,756	9,511	22,509
Natural gas liquids	6,018	7,929	13,624
Other	802	1,339	1,799
Operating expenses:			
Production:			
Lease operating	22,382	50,032	103,590
Workover and other	10,510	22,507	20,862
Taxes other than income	12,364	24,453	48,890
Gathering and other	14,677	29,279	40,281
Restructuring	—	5,168	2,886
General and administrative:			
General and administrative	19,876	78,765	73,237
Share-based compensation	21,519	4,876	14,529
Depletion, depreciation and accretion:			
Depletion—Full cost	45,204	114,775	354,344
Depreciation—Other	1,108	4,366	8,063
Accretion expense	587	1,414	1,797
Full cost ceiling impairment	420,934	754,769	2,626,305
Other operating property and equipment impairment	—	28,056	—
Other income (expenses):			
Net gain (loss) on derivative contracts	(27,740)	(17,998)	310,264
Interest expense and other, net	(28,861)	(122,249)	(232,878)
Reorganization items	(2,049)	913,722	—
Gain (loss) on extinguishment of debt	—	81,434	761,804
Gain (loss) on extinguishment of Convertible Note and modification of February 2012 Warrants	—	—	(8,219)
Income tax benefit (provision)	(4,744)	8,666	(9,086)
Production:			
Crude oil—MBbls	3,250	7,118	12,019
Natural gas—MMcf	3,011	6,560	10,123
Natural gas liquids—MBbls	501	1,096	1,457
Total MBoe(1)	4,253	9,307	15,163
Average daily production—Boe(1)	37,637	36,787	41,542
Average price per unit(2):			
Crude oil price—Bbl	$ 43.01	$ 34.85	$ 42.63
Natural gas price—Mcf	2.24	1.45	2.22
Natural gas liquids price—Bbl	12.01	7.23	9.35
Total per Boe(1)	35.87	28.53	36.17
Average cost per Boe:			
Production:			
Lease operating	$ 5.26	$ 5.38	$ 6.83
Workover and other	2.47	2.42	1.38
Taxes other than income	2.91	2.63	3.22
Gathering and other	3.45	3.15	2.66
Restructuring	—	0.56	0.19
General and administrative:			
General and administrative	4.67	8.46	4.83
Share-based compensation	5.06	0.52	0.96
Depletion	10.63	12.33	23.37

(1) Natural gas reserves are converted to oil reserves using a ratio of six Mcf to one Bbl of oil. This ratio does not assume price equivalency and, given price differentials, the price for a barrel of oil equivalent for natural gas may differ significantly from the price for a barrel of oil.

(2) Amounts exclude the impact of cash paid/received on settled contracts as we did not elect to apply hedge accounting.

Oil, natural gas and natural gas liquids revenues were $152.6 million, $265.5 million and $548.5 million for the period of September 10, 2016 through December 31, 2016 (Successor), the period of January 1, 2016 through September 9, 2016 (Predecessor) and the year ended December 31, 2015 (Predecessor), respectively. The decrease in revenues year over year was driven by the sustained decline in the prices of crude oil and natural gas along with a decrease in our average daily production. Oil and natural gas prices are inherently volatile and have decreased significantly since mid-year 2014 and have remained relatively low throughout 2016. We curtailed our drilling and shut in some production in 2016 in response to the decline in commodity prices, which resulted in a decrease in our average daily production. During the period of September 10, 2016 through December 31, 2016 (Successor) and the period of January 1, 2016 through September 9, 2016 (Predecessor), production averaged 37,637 Boe/d and 36,787 Boe/d, respectively, compared to average daily production of 41,542 Boe/d during 2015 (Predecessor).

Lease operating expenses on a per Boe basis were $5.26 per Boe, $5.38 per Boe and $6.83 per Boe for the period of September 10, 2016 through December 31, 2016 (Successor), the period of January 1, 2016 through September 9, 2016 (Predecessor) and the year ended December 31, 2015 (Predecessor), respectively. The decrease in lease operating expense per Boe from 2015 levels is primarily due to price decreases from our vendors in light of the commodity price environment.

Workover and other expenses on a per Boe basis were $2.47 per Boe, $2.42 per Boe and $1.38 per Boe for the period of September 10, 2016 through December 31, 2016 (Successor), the period of January 1, 2016 through September 9, 2016 (Predecessor) and the year ended December 31, 2015 (Predecessor), respectively. The increased costs per Boe in 2016 relate primarily to workovers in our Bakken/Three Forks area, specifically costs spent to restore production on wells.

Taxes other than income on a per Boe basis were $2.91 per Boe, $2.63 per Boe and $3.22 per Boe for the period of September 10, 2016 through December 31, 2016 (Successor), the period of January 1, 2016 through September 9, 2016 (Predecessor) and the year ended December 31, 2015 (Predecessor), respectively. Most production taxes are based on realized prices at the wellhead. As revenues or volumes from oil and natural gas sales increase or decrease, production taxes on these sales also increase or decrease.

Gathering and other expenses on a per Boe basis were $3.45 per Boe, $3.15 per Boe and $2.66 per Boe for the period of September 10, 2016 through December 31, 2016 (Successor), the period of January 1, 2016 through September 9, 2016 (Predecessor) and the year ended December 31, 2015 (Predecessor), respectively. Gathering and other expenses include gathering fees paid on our oil and natural gas production as well as rig termination or stacking charges incurred. Throughout 2016 (for the Successor and Predecessor periods combined), we stacked two rigs in response to the sustained decline in commodity prices, whereas in 2015, we stacked only one rig.

In 2016, we had reductions in our workforce due to the decrease in our drilling and developmental activities planned for the year. For the period of January 1, 2016 through September 9, 2016 (Predecessor), we incurred $5.2 million in severance costs and accelerated stock-based compensation expense related to reductions in our workforce recorded in *"Restructuring"* on the consolidated statements of operations. For the year ended December 31, 2015 (Predecessor), in conjunction with our divestitures of certain non-core properties, we incurred approximately $2.9 million in severance costs and accelerated stock-based compensation expense related to the termination of certain employees in these non-core areas.

General and administrative expense was $19.9 million, $78.8 million and $73.2 million, for the period of September 10, 2016 through December 31, 2016 (Successor), the period of January 1, 2016 through September 9, 2016 (Predecessor) and the year ended December 31, 2015 (Predecessor), respectively. General and administrative expenses increased from 2015 levels due to costs incurred in connection with efforts to restructure our indebtedness.

Share-based compensation expense was $21.5 million, $4.9 million and $14.5 million, for the period of September 10, 2016 through December 31, 2016 (Successor), the period of January 1, 2016 through September 9, 2016 (Predecessor) and the year ended December 31, 2015 (Predecessor), respectively. Share-based compensation expense decreased in the Predecessor periods due to a reduction in our workforce and increased in the Successor period due to equity awards made in conjunction with our emergence from chapter 11 bankruptcy. A portion of these awards vested immediately on the day of the grant.

Depletion for oil and natural gas properties is calculated using the unit of production method, which depletes the capitalized costs of evaluated properties plus future development costs based on the ratio of production for the current period to total reserve volumes of evaluated properties as of the beginning of the period. On a per unit basis, depletion expense was $10.63 per Boe, $12.33 per Boe and $23.37 per Boe, for the period of September 10, 2016 through December 31, 2016 (Successor), the period of January 1, 2016 through September 9, 2016 (Predecessor) and the year ended December 31, 2015 (Predecessor), respectively. The decrease in depletion expense and the depletion rate per Boe from 2015 levels is attributable to decreases in the amortizable base due to our full cost ceiling test impairments.

We utilize the full cost method of accounting to account for our oil and natural gas exploration and development activities. Under this method of accounting, we are required on a quarterly basis to determine whether the book value of our oil and natural gas properties (excluding unevaluated properties) is less than or equal to the "ceiling", based upon the expected after tax present value (discounted at 10%) of the future net cash flows from our proved reserves. Any excess of the net book value of our oil and natural gas properties over the ceiling must be recognized as a non-cash impairment expense. During 2016, the net book value of our oil and gas properties at March 31, June 30, and September 30, 2016 exceeded the respective ceiling amounts for each period. We recorded a full cost ceiling test impairment before income taxes of $420.9 million for the period of September 10, 2016 through September 30, 2016 (Successor). The impairment at September 30, 2016 primarily reflects the pricing differences between the first-day-of-the-month average price for the preceding twelve months required by Regulation S-X, Rule 4-10 and ASC 932 used in calculating the ceiling test and the forward-looking prices required by ASC 852 to estimate the fair value of the Company's oil and natural gas properties on the fresh-start reporting date, September 9, 2016. We recorded full cost ceiling test impairments before income taxes totaling $754.8 million for the period January 1, 2016 through September 9, 2016 (Predecessor). The ceiling test impairments were driven by decreases in the first-day-of-the-month average prices for crude oil used in the ceiling test calculations since December 31, 2015. We recorded full cost ceiling test impairments before income taxes totaling $2.6 billion for the year ended December 31, 2015 (Predecessor). The ceiling test impairments in 2015 were driven by decreases in the first-day-of-the-month average prices for crude oil used in the ceiling test calculations since December 31, 2014. Changes in commodity prices, production rates, levels of reserves, future development costs, transfers of unevaluated properties, capital spending and other factors will determine our actual ceiling test calculation and impairment analyses in future periods. See "*Overview*" for a discussion of potential future ceiling impairments in an environment of sustained lower commodity prices.

We review our gas gathering systems and equipment and other operating assets for impairment in accordance with ASC 360. For the period of January 1, 2016 through September 9, 2016 (Predecessor), we recorded a non-cash impairment charge of $28.1 million. The impairment relates to our gross investments of $32.8 million in gas gathering infrastructure that will not likely be economically recoverable due to our shift in exploration, drilling and developmental plans to our most economic areas as a result of the low commodity price environment.

We enter into derivative commodity instruments to economically hedge our exposure to price fluctuations on our anticipated oil and natural gas production. Consistent with prior years, we have elected not to designate any positions as cash flow hedges for accounting purposes, and accordingly, we recorded the net change in the mark-to-market value of these derivative contracts in the consolidated statements of operations. At December 31, 2016 (Successor), we had a $5.9 million derivative asset, $5.9 million of which was classified as current, and we had a $16.9 million derivative liability, $16.4 million of which was classified as current. We recorded a net derivative loss of $27.7 million ($112.4 million net unrealized loss and $84.7 million net realized gain on settled contracts) and $18.0 million ($263.7 million net unrealized loss and $245.7 million net realized gain on settled contracts) for the period of September 10, 2016 through December 31, 2016 (Successor) and for the period of January 1, 2016 through September 9, 2016 (Predecessor), respectively, compared to a net derivative gain of $310.3 million ($129.2 million net unrealized loss offset by a $439.5 million net realized gain on settled contracts) for the year ended December 31, 2015 (Predecessor).

Interest expense and other was $28.9 million, $122.2 million and $232.9 million for the period of September 10, 2016 through December 31, 2016 (Successor), the period of January 1, 2016 through September 9, 2016 (Predecessor) and the year ended December 31, 2015 (Predecessor), respectively. Capitalized interest for the period of January 1, 2016 through September 9, 2016 (Successor) and the year ended December 31, 2015 (Predecessor) was $68.2 million and $113.0 million, respectively. The Successor Company's accounting policy on the capitalization of interest establishes thresholds for the determination of a development project for the purpose of interest capitalization. Gross interest expense was $28.6 million, $195.7 million and $337.6 million for the period of September 10, 2016 through December 31, 2016 (Successor), the period of January 1, 2016 through September 9, 2016 (Predecessor) and the year ended December 31, 2015 (Predecessor), respectively. The decrease in gross interest expense from 2015 levels was primarily due to the discontinuance of interest expense on our senior notes that were cancelled as part of our chapter 11 bankruptcy proceedings.

Reorganization items represent (i) expenses or income incurred subsequent to July 27, 2016 (when we filed voluntary petitions for relief under chapter 11) as a direct result of the reorganization Plan, (ii) gains or losses from liabilities settled, and (iii) fresh-start accounting adjustments and are recorded in *"Reorganization items"* in the consolidated statements of operations. The following table summarizes the net reorganization items (in thousands):

	Successor	Predecessor
	Period from September 10, 2016 through December 31, 2016	Period from January 1, 2016 through September 9, 2016
Gain on settlement of Liabilities subject to compromise	$ —	$1,368,908
Fresh start adjustments	—	(392,232)
Reorganization professional fees and other	(2,049)	(30,287)
Write-off debt discounts/premiums and debt issuance costs	—	(32,667)
Gain (loss) on reorganization items	$(2,049)	$ 913,722

During the three months ended March 31, 2016 (Predecessor), we repurchased approximately $91.8 million principal amount of our senior unsecured notes, consisting of $24.5 million principal amount of our 9.75% senior notes due 2020, $51.8 million principal amount of our 8.875% senior notes due 2021, and $15.5 million principal amount of our 9.25% senior notes due 2022 for cash at prevailing market prices at the time of the transactions. The net cash used to make these repurchases was approximately $9.7 million. Upon settlement of the repurchases, we paid all accrued and unpaid interest since the respective interest payment dates of the notes repurchased and we recorded a net gain on the extinguishment of debt of approximately $81.4 million, which included the write-down of $0.7 million associated with related issuance costs and discounts and premiums for the respective notes. During the year ended December 31, 2015 (Predecessor), we entered into several transactions intended to reduce our long-term debt. The table below denotes the transaction description, the reduction of the principal amount of long-term debt, the write-down of associated issuance costs and discounts and premiums, and the net gain on extinguishment of debt that was recorded for each transaction:

Transaction Description	Principal Reduction	Common Stock Issuance	Issuance Cost and Discount / Premium Writedown	Net (Gain)
		(In millions)		
Unsecured Notes Exchanged for Common Stock	$ (258.0)	$231.4	$ (3.8)	$ (22.8)
Unsecured Notes Exchanged for Secured Third Lien Notes	(548.2)	—	(13.1)	(535.1)
Repurchases of Unsecured Notes	(29.7)	—	(0.3)	(29.4)
Unsecured Notes Exchanged for Secured Second Lien Notes	(176.7)	—	(2.2)	(174.5)
	$(1,012.6)	$231.4	$(19.4)	$(761.8)

During the year ended December 31, 2015 (Predecessor), we entered into an amendment to our Convertible Note and to the February 2012 Warrants, in which we recorded a net gain on the extinguishment of the Convertible Note of $5.9 million and a net loss on the modification of the February 2012 Warrants of $14.1 million.

We recorded an income tax provision of $4.7 million for the period of September 10, 2016 through December 31, 2016 (Successor) and an income tax benefit of $8.7 million for the period January 1, 2016 through September 9, 2016 (Predecessor) relating to our estimated 2016 alternative minimum tax liability and the reversal of the Predecessor estimated 2015 alternative minimum tax liability, respectively. We recorded an income tax provision of $9.1 million on a loss before income taxes of $1.9 billion for the year ended December 31, 2015 (Predecessor), related to projected alternative minimum tax.

Year Ended December 31, 2015 (Predecessor) Compared to Year Ended December 31, 2014 (Predecessor)

We reported a net loss of $1.9 billion for the year ended December 31, 2015 (Predecessor) compared to net income of $316.0 million for the comparable period in 2014 (Predecessor). The following table summarizes key items of comparison and their related change for the periods indicated. Refer to the paragraphs following the table below for a discussion around our results of operations.

	Predecessor		
	Years Ended December 31,		
In thousands (except per unit and per Boe amounts)	**2015**	**2014**	**Change**
Net income (loss)	$(1,922,621)	$ 315,956	$(2,238,577)
Operating revenues:			
Oil	512,346	1,071,319	(558,973)
Natural gas	22,509	37,101	(14,592)
Natural gas liquids	13,624	37,460	(23,836)
Other	1,799	2,381	(582)
Operating expenses:			
Production:			
Lease operating	103,590	130,239	(26,649)
Workover and other	20,862	16,193	4,669
Taxes other than income	48,890	106,331	(57,441)
Gathering and other	40,281	26,719	13,562
Restructuring	2,886	987	1,899
General and administrative:			
General and administrative	73,237	97,799	(24,562)
Share-based compensation	14,529	18,733	(4,204)
Depletion, depreciation and accretion:			
Depletion—Full cost	354,344	523,855	(169,511)
Depreciation—Other	8,063	8,744	(681)
Accretion expense	1,797	1,822	(25)
Full cost ceiling impairment	2,626,305	239,668	2,386,637
Other operating property and equipment impairment	—	35,558	(35,558)
Other income (expenses):			
Net gain (loss) on derivative contracts	310,264	518,956	(208,692)
Interest expense and other, net	(232,878)	(145,689)	(87,189)
Gain (loss) on extinguishment of debt	761,804	—	761,804
Gain (loss) on extinguishment of Convertible Note and modification of February 2012 Warrants	(8,219)	—	(8,219)
Income tax benefit (provision)	(9,086)	1,076	(10,162)
Production:			
Crude oil—MBbls	12,019	12,787	(768)
Natural gas—MMcf	10,123	8,812	1,311
Natural gas liquids—MBbls	1,457	1,113	344
Total MBoe(1)	15,163	15,369	(206)
Average daily production—Boe(1)	41,542	42,107	(565)
Average price per unit(2):			
Crude oil price—Bbl	$ 42.63	$ 83.78	$ (41.15)
Natural gas price—Mcf	2.22	4.21	(1.99)
Natural gas liquids price—Bbl	9.35	33.66	(24.31)
Total per Boe(1)	36.17	74.56	(38.39)
Average cost per Boe:			
Production:			
Lease operating	$ 6.83	$ 8.47	$ (1.64)
Workover and other	1.38	1.05	0.33
Taxes other than income	3.22	6.92	(3.70)
Gathering and other	2.66	1.74	0.92
Restructuring	0.19	0.06	0.13
General and administrative:			
General and administrative	4.83	6.36	(1.53)
Share-based compensation	0.96	1.22	(0.26)
Depletion	23.37	34.09	(10.72)

(1) Natural gas reserves are converted to oil reserves using a ratio of six Mcf to one Bbl of oil. This ratio does not assume price equivalency and, given price differentials, the price for a barrel of oil equivalent for natural gas may differ significantly from the price for a barrel of oil.

(2) Amounts exclude the impact of cash paid/received on settled contracts as we did not elect to apply hedge accounting.

For the year ended December 31, 2015 (Predecessor), oil, natural gas and natural gas liquids revenues decreased $597.4 million from the same period in 2014 due to lower average realized prices and a slight decrease in our production volumes. Average realized prices (excluding effects of hedging arrangements) decreased from $74.56 per Boe to $36.17 per Boe, representing a 51% decrease from the prior year period. Oil and natural gas prices are inherently volatile and decreased significantly since mid-year 2014. Production slightly decreased year over year, as we curtailed our drilling in response to the decline in commodity prices. However, production volumes associated with our core properties in the Bakken/Three Forks and El Halcón areas have remained flat or increased slightly year over year, as we have focused our drilling efforts on our most economic areas due to the current price environment. Sustained lower commodity prices will continue to impact our oil, natural gas and natural gas liquids revenues.

Lease operating expenses decreased $26.6 million for the year ended December 31, 2015 (Predecessor). On a per unit basis, lease operating expenses were $6.83 per Boe in 2015 compared to $8.47 per Boe in 2014. The decrease per Boe is primarily due to lower relative operating expenses on our core properties due, in part, to operational improvements and efficiencies as well as cost decreases from our vendors in light of the commodity price environment.

Workover and other expenses increased $4.7 million for the year ended December 31, 2015 (Predecessor) as compared to the same period in 2014 primarily due to $8.6 million of expenses associated with increased activity in our core areas as we continued to develop these areas.

Taxes other than income decreased $57.4 million for the year ended December 31, 2015 (Predecessor) as compared to the same period in 2014 primarily due to lower oil, natural gas and natural gas liquids revenues attributable to significantly lower commodity prices. Most production taxes are based on realized prices at the wellhead. As revenues or volumes from oil and natural gas sales increase or decrease, production taxes on these sales also increase or decrease. On a per unit basis, taxes other than income were $3.22 per Boe and $6.92 per Boe, for the years ended 2015 and 2014 (Predecessor), respectively. The decrease on a per Boe basis in 2015 is driven by a decrease in our realized average prices.

Gathering and other expenses for the year ended December 31, 2015 and 2014 (Predecessor) were $40.3 million and $26.7 million, respectively. Approximately, $29.2 million of expenses incurred in 2015 relate to gathering and other fees paid on our oil and natural gas production. Also included is a $6.0 million termination fee paid to early terminate one of our drilling rig contacts and $3.8 million of rig stacking fees. The decision to early terminate one drilling rig contract and stack another drilling rig was in response to the decline in crude oil prices.

For the year ended December 31, 2015 (Predecessor), we had reductions in our workforce due to the decrease in our drilling and developmental activities planned for the year. We incurred approximately $2.9 million in severance costs and accelerated stock-based compensation expense related to the termination of certain employees during the year. For the year ended December 31, 2014 (Predecessor), in conjunction with our divestitures of certain non-core properties, we incurred approximately $1.0 million in severance costs and accelerated stock-based compensation expense related to the termination of certain employees in these non-core areas.

General and administrative expense for the year ended December 31, 2015 (Predecessor) decreased $24.6 million to $73.2 million as compared to the same period in 2014. The decrease was primarily due to decreases in professional fees, payroll and employee related benefit costs, and transaction expenses amounting to $9.9 million, $9.3 million and $1.8 million, respectively. On a per unit basis, general and administrative expenses were $4.83 per Boe and $6.36 per Boe, for the years ended December 31, 2015 and 2014 (Predecessor), respectively.

Share-based compensation expense for the year ended December 31, 2015 (Predecessor) was $14.5 million, a decrease of $4.2 million compared to the same period in 2014. The decrease in share-based compensation expense results from forfeitures and lower fair market value for new awards granted to employees and directors during 2015.

Depletion for oil and natural gas properties is calculated using the unit of production method, which depletes the capitalized costs of evaluated properties plus future development costs based on the ratio of production volume for the current period to total remaining reserve volumes for evaluated properties as of the beginning of the period. Depletion expense decreased $169.5 million to $354.3 million for the year ended December 31, 2015 (Predecessor) compared to the same period in 2014, primarily attributable to decreases in the amortizable base due to the full cost ceiling impairments since the prior year period. On a per unit basis, depletion expense was $23.37 per Boe for the year ended December 31, 2015 (Predecessor) compared to $34.09 per Boe for the year ended December 31, 2014 (Predecessor).

We utilize the full cost method of accounting to account for our oil and natural gas exploration and development activities. Under this method of accounting, we are required on a quarterly basis to determine whether the book value of our oil and natural gas properties (excluding unevaluated properties) is less than or equal to the "ceiling," established by the expected after tax present value (discounted at 10%) of the future net cash flows from our proved reserves. Any excess of the net book value of our oil and natural gas properties over the ceiling must be recognized as a non-cash impairment expense. We recorded a full cost ceiling test impairment before income taxes of $2.6 billion for the year ended December 31, 2015 (Predecessor), compared to a full cost ceiling test impairment before income taxes of $239.7 million for the year ended December 31, 2014 (Predecessor). The ceiling test impairments in 2015 were driven by decreases in the first-day-of-the-month average prices for crude oil used in the ceiling test calculations from $94.99 per Bbl at December 31, 2014 (Predecessor) to $50.28 per Bbl at December 31, 2015 (Predecessor). Changes in commodity prices, production rates, reserve volumes, future development costs, transfers of unevaluated properties, capital spending, and other factors will determine our actual ceiling test calculation and impairment analyses in future periods. See *"Overview"* for a discussion and quantification of potential future ceiling impairments in an environment of sustained lower commodity prices.

We review our gas gathering systems and equipment and other operating assets for impairment in accordance with ASC 360. For the year ended December 31, 2014 (Predecessor), we recorded a non-cash impairment charge for gas gathering systems and other related operating assets of $35.6 million, net of $1.9 million of accumulated depreciation. The majority of the impairment represents approximately half of our gas gathering infrastructure, right-of-way and permitting investments in the Utica/Point Pleasant area. These infrastructure related investments were related to acreage in certain non-core areas of the Utica play which, at the time of evaluation for impairment in December 2014 (Predecessor), we did not plan to develop in light of the recent downtrend in oil prices, which rendered certain areas to be deemed uneconomical and/or non-strategic.

We enter into derivative commodity instruments to economically hedge our exposure to price fluctuations on our anticipated oil and natural gas production. Consistent with prior years, we have elected not to designate any positions as cash flow hedges for accounting purposes, and accordingly, we recorded the net change in the mark-to-market value of these derivative contracts in the consolidated statements of operations. At December 31, 2015 (Predecessor), we had a $365.5 million derivative asset, $348.9 million of which was classified as current, and we had a $0.3 million derivative liability, none of which was classified as current. We recorded a net derivative gain of $310.3 million ($129.2 million net unrealized loss offset by a $439.5 million net realized gain on settled contracts) for the year ended December 31, 2015 (Predecessor) compared to a net derivative gain of $518.9 million ($506.5 million net unrealized gain and $12.4 million net realized gain on settled contracts) in the prior year.

Interest expense and other increased $87.2 million for the year ended December 31, 2015 (Predecessor) from the same period in 2014. Capitalized interest for the years ended December 31, 2015 and 2014 (Predecessor) was $113.0 million and $168.9 million, respectively. The decrease in capitalized interest was driven by decreases in our unevaluated properties since 2014, which is the basis of our capitalized interest calculation. Interest expense subject to capitalization increased $19.9 million, over the prior year period, from $317.7 million in 2014 to $337.6 million in 2015. The increase in interest subject to capitalization is primarily due to the issuance of our 2020 Second Lien Notes since the prior year period.

During the year ended December 31, 2015 (Predecessor), we entered into several transactions intended to reduce our long-term debt. The table below denotes the transaction description, the reduction of the principal amount of long-term debt, the write-down of associated issuance costs and discounts and premiums, and the net gain on extinguishment of debt that was recorded for each transaction:

Transaction Description	Principal Reduction	Common Stock Issuance	Issuance Cost and Discount / Premium Writedown	Net (Gain)
		(In millions)		
Unsecured Notes Exchanged for Common Stock	$ (258.0)	$231.4	$ (3.8)	$ (22.8)
Unsecured Notes Exchanged for Secured Third Lien Notes	(548.2)	—	(13.1)	(535.1)
Repurchases of Unsecured Notes	(29.7)	—	(0.3)	(29.4)
Unsecured Notes Exchanged for Secured Second Lien Notes	(176.7)	—	(2.2)	(174.5)
	$(1,012.6)	$231.4	$(19.4)	$(761.8)

During the year ended December 31, 2015 (Predecessor), we entered into an amendment to our Convertible Note and to the February 2012 Warrants, in which we recorded a net gain on the extinguishment of the Convertible Note of $5.9 million and a net loss on the modification of the February 2012 Warrants of $14.1 million.

We recorded an income tax provision of $9.1 million on a loss before income taxes of $1.9 billion for the year ended December 31, 2015 (Predecessor). The provision represents projected alternative minimum tax. For the year ended December 31, 2014 (Predecessor), we recorded an income tax benefit of $1.1 million on income before income taxes of $314.9 million. The benefit reflects the impact of the change in the valuation allowance for the year of $102.0 million.

Recently Issued Accounting Pronouncements

We discuss recently adopted and issued accounting standards in Item 8. *Consolidated Financial Statements and Supplementary Data*—Note 1, "*Summary of Significant Events and Accounting Policies*."

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Derivative Instruments and Hedging Activity

We are exposed to various risks including energy commodity price risk. When oil, natural gas, and natural gas liquids prices decline significantly our ability to finance our capital budget and operations may be adversely impacted. We expect energy prices to remain volatile and unpredictable, therefore we have designed a risk management policy which provides for the use of derivative instruments to provide partial protection against declines in oil and natural gas prices by reducing the risk of price volatility and the affect it could have on our operations. The types of derivative instruments that we typically utilize include costless collars, swaps, and deferred put options. The total volumes which we hedge through the use of our derivative instruments varies from period to period, however, generally our objective is to hedge approximately 70% to 80% of our current and anticipated production for the next 18 to 24 months, when derivative contracts are available at terms (or prices) acceptable to us. Our hedge policies and objectives may change significantly as our operational profile changes and/or commodities prices change. We do not enter into derivative contracts for speculative trading purposes.

We are exposed to market risk on our open derivative contracts related to potential non-performance by our counterparties. It is our policy to enter into derivative contracts only with counterparties that are creditworthy institutions deemed by management as competent and competitive market makers. We did not post collateral under any of these contracts as they are secured under our Senior Credit Agreement or are uncollateralized trades. Please refer to Item 8. *Consolidated Financial Statements and Supplementary Data*—Note 9, *"Derivative and Hedging Activities,"* for additional information.

We account for our derivative activities under the provisions of ASC 815, *Derivatives and Hedging*, (ASC 815). ASC 815 establishes accounting and reporting that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at fair value. See Item 8. *Consolidated Financial Statements and Supplementary Data*—Note 9, *"Derivative and Hedging Activities,"* for more details.

Fair Market Value of Financial Instruments

The estimated fair values for financial instruments under ASC 825, *Financial Instruments*, (ASC 825) are determined at discrete points in time based on relevant market information. These estimates involve uncertainties and cannot be determined with precision. The estimated fair value of cash, cash equivalents, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. See Item 8. *Consolidated Financial Statements and Supplementary Data*—Note 8, "*Fair Value Measurements,"* for additional information.

Interest Rate Sensitivity

We are also exposed to market risk related to adverse changes in interest rates. Our interest rate risk exposure results primarily from fluctuations in short-term rates, which are LIBOR and ABR based and may result in reductions of earnings or cash flows due to increases in the interest rates we pay on these obligations.

At December 31, 2016 (Successor), the principal amount of our total long-term debt was $998.8 million, of which approximately 81.4% bears interest at a weighted average fixed interest rate of 9.09% per year. The remaining 18.6% of our total long-term debt at December 31, 2016 (Successor) bears interest at floating or market interest rates that at our option are tied to prime rate or LIBOR. Fluctuations in market interest rates will cause our annual interest costs to fluctuate. At December 31, 2016 (Successor), the weighted average interest rate on our variable rate debt was 3.74% per year. If the balance of our variable rate debt at December 31, 2016 (Successor) were to remain constant, a 10% change in market interest rates would impact our cash flow by approximately $0.7 million per year.

ITEM 8. CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Halcón Resources Corporation (the Company), including the Company's Chief Executive Officer and Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. The Company's internal control system was designed to provide reasonable assurance to the Company's Management and Board of Directors regarding the preparation and fair presentation of published 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.

Management conducted an evaluation of the effectiveness of internal control over financial reporting based on the *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013. Based on this evaluation, management concluded that Halcón Resources Corporation's internal control over financial reporting was effective as of December 31, 2016.

Deloitte & Touche LLP, the Company's independent registered public accounting firm, has issued an attestation report on the effectiveness of the Company's internal control over financial reporting as of December 31, 2016 which is included herein.

/s/ FLOYD C. WILSON	/s/ MARK J. MIZE
Floyd C. Wilson *Chairman of the Board, Chief Executive Officer and President*	Mark J. Mize *Executive Vice President,* *Chief Financial Officer and Treasurer*

Houston, Texas
February 28, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Halcón Resources Corporation
Houston, Texas

We have audited the internal control over financial reporting of Halcón Resources Corporation and subsidiaries (the "Company") as of December 31, 2016, based on criteria established in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. 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 conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of the Company as of December 31, 2016 (Successor Company balance sheet) and 2015 (Predecessor Company balance sheet), and the related consolidated statements of operations, stockholders' equity (deficit), and cash flows for the period of September 10, 2016 to December 31, 2016 (Successor Company operations), the period of January 1, 2016 to September 9, 2016, and for each of the two years in the period ended December 31, 2015 (Predecessor Company operations) and our report dated February 28, 2017 expressed an unqualified opinion on those financial statements.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 28, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Halcón Resources Corporation
Houston, Texas

We have audited the accompanying balance sheet of Halcón Resources Corporation and subsidiaries (the "Company") as of December 31, 2016 (Successor Company balance sheet) and 2015 (Predecessor Company balance sheet), and the related consolidated statements of operations, stockholders' equity, and cash flows for the period of September 10, 2016 to December 31, 2016 (Successor Company operations), the period of January 1, 2016 to September 9, 2016, and for each of the two years in the period ended December 31, 2015 (Predecessor Company operations). These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 2 to the financial statements, on September 8, 2016, the Bankruptcy Court entered an order confirming the plan of reorganization which became effective on September 9, 2016.

Accordingly, the accompanying financial statements have been prepared in conformity with AICPA Statement of Position 90-7, *Financial Reporting by Entities in Reorganization Under the Bankruptcy Code*, for the Successor Company as a new entity with assets, liabilities, and a capital structure having carrying values not comparable with prior periods as described in Note [2] to the financial statements.

In our opinion, the Successor Company financial statements present fairly, in all material respects, the financial position of Halcón Resources Corporation and subsidiaries as of December 31, 2016, and the results of its operations and its cash flows for the period of September 10, 2016 to December 31, 2016, in conformity with accounting principles generally accepted in the United States of America. Further, in our opinion, the Predecessor Company financial statements referred to above present fairly, in all material respects, the financial position of the Predecessor Company as of December 31, 2015, and the results of its operations and its cash flows for the period of January 1, 2016 to September 9, 2016, and for each of the two years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2017 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 28, 2017

HALCÓN RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share amounts)

	Successor	Predecessor		
	Period from September 10, 2016 through December 31, 2016	Period from January 1, 2016 through September 9, 2016	Years Ended December 31, 2015	Years Ended December 31, 2014
Operating revenues:				
Oil, natural gas and natural gas liquids sales:				
Oil	$ 139,786	$ 248,064	$ 512,346	$1,071,319
Natural gas	6,756	9,511	22,509	37,101
Natural gas liquids	6,018	7,929	13,624	37,460
Total oil, natural gas and natural gas liquids sales	152,560	265,504	548,479	1,145,880
Other	802	1,339	1,799	2,381
Total operating revenues	153,362	266,843	550,278	1,148,261
Operating expenses:				
Production:				
Lease operating	22,382	50,032	103,590	130,239
Workover and other	10,510	22,507	20,862	16,193
Taxes other than income	12,364	24,453	48,890	106,331
Gathering and other	14,677	29,279	40,281	26,719
Restructuring	—	5,168	2,886	987
General and administrative	41,395	83,641	87,766	116,532
Depletion, depreciation and accretion	46,899	120,555	364,204	534,421
Full cost ceiling impairment	420,934	754,769	2,626,305	239,668
Other operating property and equipment impairment	—	28,056	—	35,558
Total operating expenses	569,161	1,118,460	3,294,784	1,206,648
Income (loss) from operations	(415,799)	(851,617)	(2,744,506)	(58,387)
Other income (expenses):				
Net gain (loss) on derivative contracts	(27,740)	(17,998)	310,264	518,956
Interest expense and other, net	(28,861)	(122,249)	(232,878)	(145,689)
Reorganization items	(2,049)	913,722	—	—
Gain (loss) on extinguishment of debt	—	81,434	761,804	—
Gain (loss) on extinguishment of Convertible Note and modification of February 2012 Warrants	—	—	(8,219)	—
Total other income (expenses)	(58,650)	854,909	830,971	373,267
Income (loss) before income taxes	(474,449)	3,292	(1,913,535)	314,880
Income tax benefit (provision)	(4,744)	8,666	(9,086)	1,076
Net income (loss)	(479,193)	11,958	(1,922,621)	315,956
Series A preferred dividends	—	(8,847)	(17,517)	(19,838)
Preferred dividends and accretion on redeemable noncontrolling interest	(791)	(35,905)	(66,820)	(13,176)
Net income (loss) available to common stockholders	$(479,984)	$ (32,794)	$(2,006,958)	$ 282,942
Net income (loss) per share of common stock:				
Basic	$ (5.26)	$ (0.27)	$ (18.66)	$ 3.40
Diluted	$ (5.26)	$ (0.27)	$ (18.66)	$ 2.93
Weighted average common shares outstanding:				
Basic	91,228	120,513	107,531	83,155
Diluted	91,228	120,513	107,531	108,481

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

HALCÓN RESOURCES CORPORATION
CONSOLIDATED BALANCE SHEETS
(In thousands, except share and per share amounts)

	Successor	Predecessor
	December 31, 2016	December 31, 2015
Current assets:		
Cash	$ 24	$ 8,026
Accounts receivable	147,762	173,624
Receivables from derivative contracts	5,923	348,861
Restricted cash	182	16,812
Prepaids and other	6,758	9,270
Total current assets	160,649	556,593
Oil and natural gas properties (full cost method):		
Evaluated	1,269,034	7,060,721
Unevaluated	316,439	1,641,356
Gross oil and natural gas properties	1,585,473	8,702,077
Less—accumulated depletion	(465,849)	(5,933,688)
Net oil and natural gas properties	1,119,624	2,768,389
Other operating property and equipment:		
Gas gathering and other operating assets	38,617	130,090
Less—accumulated depreciation	(1,107)	(22,435)
Net other operating property and equipment	37,510	107,655
Other noncurrent assets:		
Receivables from derivative contracts	—	16,614
Debt issuance costs, net	—	7,633
Funds in escrow and other	1,887	1,808
Total assets	$1,319,670	$ 3,458,692
Current liabilities:		
Accounts payable and accrued liabilities	$ 186,184	$ 295,085
Liabilities from derivative contracts	16,434	—
Other	4,935	163
Total current liabilities	207,553	295,248
Long-term debt, net	964,653	2,873,637
Other noncurrent liabilities:		
Liabilities from derivative contracts	486	290
Asset retirement obligations	31,985	46,853
Other	2,305	6,264
Commitments and contingencies (Note 11)		
Mezzanine equity:		
Redeemable noncontrolling interest	—	183,986
Stockholders' equity:		
Predecessor Preferred stock: 1,000,000 shares of $0.0001 par value authorized; 244,724 shares of 5.75% Cumulative Perpetual Convertible Series A, issued and outstanding	—	—
Predecessor Common stock: 1,340,000,000 shares of $0.0001 par value authorized;122,523,559 shares issued and outstanding	—	12
Predecessor Additional paid-in capital	—	3,283,097
Successor Common stock: 1,000,000,000 shares of $0.0001 par value authorized; 92,991,183 shares issued and outstanding	9	—
Successor Additional paid-in capital	592,663	—
Retained earnings (accumulated deficit)	(479,984)	(3,230,695)
Total stockholders' equity	112,688	52,414
Total liabilities and stockholders' equity	$1,319,670	$ 3,458,692

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

HALCÓN RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In thousands)

	Preferred Stock		Common Stock		Additional Paid-In Capital	Accumulated Deficit	Stockholders' Equity
	Shares	Amount	Shares	Amount			
Balances at December 31, 2013 (Predecessor)	345	$ —	83,146	$ 8	$ 2,953,819	$(1,506,217)	$ 1,447,610
Net income (loss)	—	—	—	—	—	315,956	315,956
Dividends on Series A preferred stock	—	—	653	—	14,878	(19,838)	(4,960)
Preferred dividends on redeemable noncontrolling interest	—	—	—	—	—	(6,543)	(6,543)
Accretion of redeemable noncontrolling interest	—	—	—	—	—	(6,633)	(6,633)
Offering costs	—	—	—	—	39	—	39
Long-term incentive plan grants	—	—	1,878	—	—	—	—
Long-term incentive plan forfeitures	—	—	(91)	—	—	—	—
Reduction in shares to cover individuals' tax withholding	—	—	(24)	—	(453)	—	(453)
Share-based compensation	—	—	—	—	27,153	—	27,153
Balances at December 31, 2014 (Predecessor)	345	—	85,562	8	2,995,436	(1,223,275)	1,772,169
Net income (loss)	—	—	—	—	—	(1,922,621)	(1,922,621)
Dividends on Series A preferred stock	—	—	1,354	1	9,801	(17,979)	(8,177)
Conversion of Series A preferred stock	(100)	—	3,258	—	—	—	—
Preferred dividends on redeemable noncontrolling interest	—	—	—	—	—	(12,614)	(12,614)
Accretion of redeemable noncontrolling interest	—	—	—	—	—	(53,561)	(53,561)
Change in fair value of redeemable noncontrolling interest	—	—	—	—	—	(645)	(645)
Common stock issuance	—	—	1,888	—	15,356	—	15,356
Common stock issuance on conversion of senior notes	—	—	28,955	3	231,380	—	231,383
Modification of February 2012 Warrants	—	—	—	—	14,129	—	14,129
Offering costs	—	—	—	—	(1,871)	—	(1,871)
Long-term incentive plan grants	—	—	2,048	—	—	—	—
Long-term incentive plan forfeitures	—	—	(388)	—	—	—	—
Reduction in shares to cover individuals' tax withholding	—	—	(153)	—	(947)	—	(947)
Share-based compensation	—	—	—	—	19,813	—	19,813
Balances at December 31, 2015 (Predecessor)	245	—	122,524	12	3,283,097	(3,230,695)	52,414
Net income (loss)	—	—	—	—	—	11,958	11,958
Conversion of Series A preferred stock	(23)	—	724	—	—	—	—
Preferred dividends on redeemable noncontrolling interest	—	—	—	—	—	(9,329)	(9,329)
Accretion of redeemable noncontrolling interest	—	—	—	—	—	(26,576)	(26,576)
Fair value of equity issued to Predecessor common stockholders	—	—	—	—	(22,176)	—	(22,176)
Cash payment to Preferred Holders	—	—	—	—	(11,100)	—	(11,100)
Reverse stock split rounding	—	—	5	—	—	—	—
Offering costs	—	—	—	—	(10)	—	(10)
Long-term incentive plan forfeitures	—	—	(517)	—	—	—	—
Reduction in shares to cover individuals' tax withholding	—	—	(498)	—	(176)	—	(176)
Share-based compensation	—	—	—	—	4,995	—	4,995
Balances at September 9, 2016 (Predecessor)	222	$ —	122,238	$ 12	$ 3,254,630	(3,254,642)	$ —
Cancellation of Predecessor equity	(222)	$ —	(122,238)	$ (12)	$(3,254,630)	$ 3,254,642	$ —
Balances at September 9, 2016 (Predecessor)	—	$ —	—	$ —	$ —	—	$ —
Issuance of Successor common stock and warrants	—	$ —	90,000	$ 9	$ 571,114	$ —	$ 571,123
Balances at September 9, 2016 (Successor)	—	$ —	90,000	$ 9	$ 571,114	$ —	$ 571,123
Net income (loss)	—	—	—	—	—	(479,193)	(479,193)
Preferred dividends on redeemable noncontrolling interest	—	—	—	—	—	(791)	(791)
Long-term incentive plan grants	—	—	2,991	—	—	—	—
Share-based compensation	—	—	—	—	21,549	—	21,549
Balances at December 31, 2016 (Successor)	—	$ —	92,991	$ 9	$ 592,663	$ (479,984)	$ 112,688

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

HALCÓN RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Successor	Predecessor		
	Period from September 10, 2016 through December 31, 2016	Period from January 1, 2016 through September 9, 2016	Years Ended December 31, 2015	Years Ended December 31, 2014
Cash flows from operating activities:				
Net income (loss)	$(479,193)	$ 11,958	$(1,922,621)	$ 315,956
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:				
Depletion, depreciation and accretion	46,899	120,555	364,204	534,421
Full cost ceiling impairment	420,934	754,769	2,626,305	239,668
Other operating property and equipment impairment	—	28,056	—	35,558
Share-based compensation, net	21,519	4,876	14,529	18,733
Unrealized loss (gain) on derivative contracts	112,449	263,732	129,282	(508,285)
Amortization and write-off of deferred loan costs	—	6,371	7,357	4,315
Non-cash interest and amortization of discount and premium	2,506	1,515	2,509	2,780
Reorganization items	(15,963)	(929,084)	—	—
Loss (gain) on extinguishment of debt	—	(81,434)	(761,804)	—
Loss (gain) on extinguishment of Convertible Note and modification of February 2012 Warrants	—	—	8,219	—
Accrued settlements on derivative contracts	(18,498)	—	(47,011)	(25,868)
Other expense (income)	79	(4,233)	8,934	(2,435)
Change in assets and liabilities:				
Accounts receivable	(20,459)	47,920	86,411	85,767
Prepaids and other	857	(4,329)	3,714	7,474
Accounts payable and accrued liabilities	32,006	(45,324)	(53,029)	(40,150)
Net cash provided by (used in) operating activities	103,136	175,348	466,999	667,934
Cash flows from investing activities:				
Oil and natural gas capital expenditures	(61,459)	(226,617)	(659,419)	(1,524,341)
Proceeds received from sales of oil and natural gas assets	888	(407)	1,222	484,184
Advance on carried interest	—	—	—	(189,442)
Other operating property and equipment capital expenditures	(750)	(950)	(10,838)	(43,083)
Funds held in escrow and other	(1,721)	200	1,903	1,589
Net cash provided by (used in) investing activities	(63,042)	(227,774)	(667,132)	(1,271,093)
Cash flows from financing activities:				
Proceeds from borrowings	115,000	886,000	1,834,000	2,276,000
Repayments of borrowings	(159,000)	(727,648)	(1,643,804)	(1,719,000)
Cash payments to Noteholders and Preferred Holders	(10,013)	(97,521)	—	—
Debt issuance costs	—	(1,977)	(29,568)	(819)
Series A preferred dividends	—	—	(8,177)	(4,960)
Common stock issued	—	—	15,356	—
HK TMS, LLC preferred stock issued	—	—	—	110,051
HK TMS, LLC tranche rights	—	—	—	4,516
Preferred dividends on redeemable noncontrolling interest	—	—	—	(3,518)
Restricted cash	—	—	(543)	(16,131)
Offering costs and other	—	(511)	(2,818)	(2,101)
Net cash provided by (used in) financing activities	(54,013)	58,343	164,446	644,038
Net increase (decrease) in cash	(13,919)	5,917	(35,687)	40,879
Cash at beginning of period	13,943	8,026	43,713	2,834
Cash at end of period	$ 24	$ 13,943	$ 8,026	$ 43,713
Supplemental cash flow information:				
Cash paid for interest, net of capitalized interest	$ 3,605	$ 139,930	$ 204,178	$ 132,557
Cash paid (refunded) for income taxes	5,000	—	(3,078)	(8,600)
Cash paid for reorganization items	18,012	15,362	—	—
Disclosure of non-cash investing and financing activities:				
Accrued capitalized interest	$ —	$ (23,966)	$ (1,417)	$ (1,180)
Asset retirement obligations	513	939	6,742	(1,262)
Series A preferred dividends paid in common stock	—	—	9,802	14,878
Preferred dividends on redeemable noncontrolling interest paid-in-kind	791	9,329	12,614	3,025
Accretion of redeemable noncontrolling interest	—	26,576	53,561	6,633
Change in fair value of redeemable noncontrolling interest	—	—	645	—
Common stock issued on conversion of senior notes	—	—	231,383	—
Third Lien Notes issued on conversion of senior notes	—	—	1,017,970	—
2022 Second Lien Notes issued on conversion of senior notes	—	—	112,826	—
Accrued debt issuance costs	—	1,176	(1,176)	—
Receivable for sale of oil and natural gas properties	—	—	—	1,000

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

HALCÓN RESOURCES CORPORATION
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT EVENTS AND ACCOUNTING POLICIES

Basis of Presentation and Principles of Consolidation

Halcón Resources Corporation (Halcón or the Company) is an independent energy company focused on the acquisition, production, exploration and development of onshore liquids-rich oil and natural gas assets in the United States. The consolidated financial statements include the accounts of all majority-owned, controlled subsidiaries. The Company operates in one segment which focuses on oil and natural gas acquisition, production, exploration and development. The Company's oil and natural gas properties are managed as a whole rather than through discrete operating areas. Operational information is tracked by operating area; however, financial performance is assessed as a whole. Allocation of capital is made across the Company's entire portfolio without regard to operating area. All intercompany accounts and transactions have been eliminated. The Company has evaluated events or transactions through the date of issuance of this report in conjunction with the preparation of these consolidated financial statements.

Emergence from Voluntary Reorganization under Chapter 11

On July 27, 2016 (the Petition Date), the Company and certain of its subsidiaries (the Halcón Entities) filed voluntary petitions for relief under chapter 11 of the United States Bankruptcy Code in the U.S. Bankruptcy Court in the District of Delaware (the Bankruptcy Court) to pursue a joint prepackaged plan of reorganization (the Plan). On September 8, 2016, the Bankruptcy Court entered an order confirming the Plan and on September 9, 2016, the Plan became effective (the Effective Date) and the Halcón Entities emerged from chapter 11 bankruptcy. The Company's subsidiary, HK TMS, LLC which was divested on September 30, 2016, was not part of the chapter 11 bankruptcy filings. See Note 2, *"Reorganization,"* for further details on the Company's chapter 11 bankruptcy and the Plan and Note 5, *"Divestitures,"* for further details on the divestiture of HK TMS, LLC.

Upon emergence from chapter 11 bankruptcy, the Company adopted fresh-start accounting in accordance with provisions of the Financial Accounting Standards Board's (FASB) Accounting Standards Codification (ASC) 852, *Reorganizations* (ASC 852) which resulted in the Company becoming a new entity for financial reporting purposes on the Effective Date. Upon the adoption of fresh-start accounting, the Company's assets and liabilities were recorded at their fair values as of the fresh-start reporting date. As a result of the adoption of fresh-start accounting, the Company's consolidated financial statements subsequent to September 9, 2016 are not comparable to its consolidated financial statements prior to, and including, September 9, 2016. See Note 3, *"Fresh-start Accounting,"* for further details on the impact of fresh-start accounting on the Company's consolidated financial statements.

References to "Successor" or "Successor Company" relate to the financial position and results of operations of the reorganized Company subsequent to September 9, 2016. References to "Predecessor" or "Predecessor Company" relate to the financial position and results of operations of the Company prior to, and including, September 9, 2016.

Use of Estimates

The preparation of the Company's consolidated financial statements in conformity with accounting principles generally accepted in the United States requires the Company's management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. Estimates and

1. SUMMARY OF SIGNIFICANT EVENTS AND ACCOUNTING POLICIES (Continued)

assumptions that, in the opinion of management of the Company, are significant include oil and natural gas revenue accruals, capital and operating expense accruals, oil and natural gas reserves, depletion relating to oil and natural gas properties, asset retirement obligations, fair value estimates, including estimates of Reorganization Value, Enterprise Value and the fair value of assets and liabilities recorded as a result of the adoption of fresh-start accounting, and income taxes. The Company bases its estimates and judgments on historical experience and on various other assumptions and information that are believed to be reasonable under the circumstances. Estimates and assumptions about future events and their effects cannot be perceived with certainty and, accordingly, these estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as the Company's operating environment changes. Actual results may differ from the estimates and assumptions used in the preparation of the Company's consolidated financial statements.

Accounts Receivable and Allowance for Doubtful Accounts

The Company's accounts receivable are primarily receivables from joint interest owners and oil and natural gas purchasers. Accounts receivable are recorded at the amount due, less an allowance for doubtful accounts, when applicable. The Company establishes provisions for losses on accounts receivable if it determines that collection of all or part of the outstanding balance is doubtful. The Company regularly reviews collectability and establishes or adjusts the allowance for doubtful accounts as necessary using the specific identification method. There were no significant allowances for doubtful accounts as of December 31, 2016 (Successor) or 2015 (Predecessor).

Oil and Natural Gas Properties

The Company uses the full cost method of accounting for its investment in oil and natural gas properties as prescribed by the United States Securities and Exchange Commission (SEC). Accordingly, all costs incurred in the acquisition, exploration and development of proved and unproved oil and natural gas properties, including the costs of abandoned properties, dry holes, geophysical costs, and annual lease rentals are capitalized. All general and administrative corporate costs unrelated to drilling activities are expensed as incurred. Sales or other dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to proved reserves would significantly change. Depletion of evaluated oil and natural gas properties is computed on the units of production method based on proved reserves. The net capitalized costs of evaluated oil and natural gas properties are subject to a full cost ceiling limitation in which the costs are not allowed to exceed their related estimated future net revenues discounted at 10%, net of tax considerations.

Costs associated with unevaluated properties are excluded from the full cost pool until the Company has made a determination as to the existence of proved reserves. The Company reviews its unevaluated properties at the end of each quarter to determine whether the costs incurred should be transferred to the full cost pool and thereby subject to amortization. Investments in unevaluated oil and natural gas properties and exploration and development projects for which depletion expense is not currently recognized, and for which exploration or development activities are in progress, qualify for interest capitalization. The Company determines capitalized interest, when applicable, by multiplying the Company's weighted-average borrowing cost on debt by the average amount of qualifying costs incurred that were excluded from the full cost pool; however, the amount of capitalized interest cannot exceed the amount of gross interest expense incurred in any given period. The Successor Company's

1. SUMMARY OF SIGNIFICANT EVENTS AND ACCOUNTING POLICIES (Continued)

accounting policy on the capitalization of interest establishes thresholds for the determination of a development project for the purpose of interest capitalization.

Other Operating Property and Equipment

Gas gathering systems and equipment are recorded at cost. Depreciation is calculated using the straight-line method over a 30-year or 10-year estimated useful life applicable to gas gathering systems and compressed natural gas facilities, respectively. Upon disposition, the cost and accumulated depreciation are removed and any gains or losses are reflected in current operations. Maintenance and repair costs are charged to operating expense as incurred. Material expenditures which increase the life or productive capacity of an asset are capitalized and depreciated over the estimated remaining useful life of the asset. With the adoption of fresh-start accounting, the Company recorded its gas gathering systems and equipment at fair value totaling approximately $16.3 million as of the fresh-start reporting date. Refer to Note 3, *''Fresh-start Accounting,''* for a discussion of the valuation approach used. At December 31, 2016 (Successor) and 2015 (Predecessor), the Company had approximately $16.4 million and $87.2 million capitalized, respectively, related to the construction of its gas gathering systems, after any amounts impaired.

Other operating assets are recorded at cost. Depreciation is calculated using the straight-line method over the following estimated useful lives: automobiles and computers, three years; computer software, fixtures, furniture and equipment, five years or the lesser of lease term; trailers, seven years; heavy equipment, ten years; buildings, twenty years and leasehold improvements, lease term. Upon disposition, the cost and accumulated depreciation are removed and any gains or losses are reflected in current operations. Maintenance and repair costs are charged to operating expense as incurred. Material expenditures which increase the life of an asset are capitalized and depreciated over the estimated remaining useful life of the asset. With the adoption of fresh-start accounting, the Company recorded its other operating assets at fair value totaling approximately $21.8 million as of the fresh-start reporting date. Refer to Note 3, *''Fresh-start Accounting,''* for a discussion of the valuation approach used.

The Company reviews its gas gathering systems and equipment and other operating assets for impairment in accordance with ASC 360, *Property, Plant, and Equipment* (ASC 360). ASC 360 requires the Company to evaluate gas gathering systems and equipment and other operating assets for impairment as events occur or circumstances change that would more likely than not reduce the fair value below the carrying amount. If the carrying amount is not recoverable from its undiscounted cash flows, then the Company would recognize an impairment loss for the difference between the carrying amount and the current fair value. Further, the Company evaluates the remaining useful lives of its gas gathering systems and equipment and other operating assets at each reporting period to determine whether events and circumstances warrant a revision to the remaining depreciation periods. For the three months ended March 31, 2016 (Predecessor), the Company recorded a non-cash impairment charge of $28.1 million related to $32.8 million gross investments in gas gathering infrastructure that were deemed non-economical due to a shift in exploration, drilling and developmental plans in a low commodity price environment. For the year ended December 31, 2014 (Predecessor), the Company recorded a non-cash impairment charge for gas gathering systems and other related operating assets of $35.6 million, net of $1.9 million of accumulated depreciation. The majority of the impairment represents approximately half of the Predecessor Company's gas gathering infrastructure, right-of-way and permitting investments in the Utica / Point Pleasant area (Utica). These infrastructure related

1. SUMMARY OF SIGNIFICANT EVENTS AND ACCOUNTING POLICIES (Continued)

investments were related to acreage in certain non-core areas of the Utica play which, at the time of evaluation for impairment in December 2014, the Predecessor Company did not plan to develop in light of the downtrend in oil prices which rendered certain areas to be deemed uneconomical and/or non-strategic. These impairments were recorded in *"Other operating property and equipment impairment"* in the Company's consolidated statements of operations and in *"Gas gathering and other operating assets"* in the Company's consolidated balance sheets.

In accordance with ASC 820, *Fair Value Measurements and Disclosures* (ASC 820), a financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. The estimate of the fair value of the Company's gas gathering systems was based on an income approach that estimated future cash flows associated with those assets over the remaining asset lives. This estimation includes the use of unobservable inputs, such as estimated future production, gathering and compression revenues and operating expenses. The use of these unobservable inputs results in the fair value estimate of the Company's gas gathering systems being classified as Level 3.

Revenue Recognition

Revenues from the sale of crude oil, natural gas, and natural gas liquids are recognized when the product is delivered at a fixed or determinable price, title has transferred, and collectability is reasonably assured and evidenced by a contract. The Company follows the entitlement method of accounting for crude oil and natural gas sales, recognizing as revenues only its net interest share of all production sold. Any amount attributable to the sale of production in excess of or less than the Company's net interest is recorded as a balancing asset or liability. At December 31, 2016 (Successor) and 2015 (Predecessor), the Company's imbalances were immaterial.

Concentrations of Credit Risk

The Company operates a substantial portion of its oil and natural gas properties. As the operator of a property, the Company makes full payments for costs associated with the property and seeks reimbursement from the other working interest owners in the property for their share of those costs. The Company's joint interest partners consist primarily of independent oil and natural gas producers. If the oil and natural gas exploration and production industry in general was adversely affected, the ability of the Company's joint interest partners to reimburse the Company could be adversely affected.

The purchasers of the Company's oil and natural gas production consist primarily of independent marketers, major oil and natural gas companies and gas pipeline companies. Historically, the Company has not experienced any significant losses from uncollectible accounts. For the combined periods, September 10, 2016 through December 31, 2016 (Successor) and January 1, 2016 through September 9, 2016 (Predecessor), two individual purchasers of the Company's production, Crestwood Midstream Partners, formerly Arrow Field Services LLC (Crestwood), and Energy Marketing Inc. (Suncor), each accounted for more than 10% of total sales, collectively representing 58%, of the Company's total sales for the period. In 2015 and 2014 (Predecessor), three individual purchasers of the Company's production, Crestwood, Sunoco Inc. and Suncor, each accounted for more than 10% of total sales, collectively representing 57% and 66%, respectively, of the Company's total sales for the years.

1. SUMMARY OF SIGNIFICANT EVENTS AND ACCOUNTING POLICIES (Continued)

Risk Management Activities

The Company follows ASC 815, *Derivatives and Hedging* (ASC 815). From time to time, when derivative contracts are available at terms (or prices) acceptable to the Company, it may hedge a portion of its forecasted oil, natural gas, and natural gas liquids production. Derivative contracts entered into by the Company have consisted of transactions in which the Company hedges the variability of cash flow related to a forecasted transaction. The Company recognized all derivative instruments as either assets or liabilities in the consolidated balance sheets at fair value. The Company has elected to not designate any of its positions for hedge accounting. Accordingly, the Company records the net change in the mark-to-market valuation of these positions, as well as payments and receipts on settled contracts, in "*Net gain (loss) on derivative contracts*" on the consolidated statements of operations.

Income Taxes

The Company accounts for income taxes using the asset and liability method wherein deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. Deferred tax assets are reduced by a valuation allowance if, based on the weight of available evidence, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

The Company follows ASC 740, *Income Taxes* (ASC 740). ASC 740 creates a single model to address accounting for the uncertainty in income tax positions and prescribes a minimum recognition threshold a tax position must meet before recognition in the consolidated financial statements.

The evaluation of a tax position in accordance with ASC 740 is a two-step process. The first step is a recognition process to determine whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. In evaluating whether a tax position has met the more likely than not recognition threshold, it is presumed that the position will be examined by the appropriate taxing authority with full knowledge of all relevant information. The second step is a measurement process whereby a tax position that meets the more likely than not recognition threshold is calculated to determine the amount of benefit/expense to recognize in the consolidated financial statements. The tax position is measured at the largest amount of benefit/expense that is more likely than not of being realized upon ultimate settlement.

The Company has no liability for unrecognized tax benefits as of December 31, 2016 (Successor) and 2015 (Predecessor). Accordingly, there is no amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate and there is no amount of interest or penalties currently recognized in the consolidated statements of operations or consolidated balance sheets as of December 31, 2016 (Successor), 2015 and 2014 (Predecessor). In addition, the Company does not believe that there are any positions for which it is reasonably possible that the total amount of unrecognized tax benefits will significantly increase or decrease within the next twelve months.

1. SUMMARY OF SIGNIFICANT EVENTS AND ACCOUNTING POLICIES (Continued)

The Company includes interest and penalties relating to uncertain tax positions within "*Interest expense and other, net*" on the Company's consolidated statements of operations. Refer to Note 14, "*Income Taxes,*" for more details.

Generally, the Company's tax years 2013 through 2016 are either currently under audit or remain open and subject to examination by federal tax authorities or the tax authorities in Louisiana, Mississippi, North Dakota, Oklahoma, Texas, Pennsylvania, Ohio and certain other state taxing jurisdictions where the Company has, or previously had, principal operations. In certain of these jurisdictions, the Company operates through more than one legal entity, each of which may have different open years subject to examination. Additionally, it is important to note that years are open for examination until the statute of limitations in each respective jurisdiction expires.

Tax audits may be ongoing at any point in time. Tax liabilities are recorded based on estimates of additional taxes which may be due upon the conclusion of these audits. Estimates of these tax liabilities are made based upon prior experience and are updated for changes in facts and circumstances. However, due to the uncertain and complex application of tax regulations, it is possible that the ultimate resolution of audits may result in liabilities which could be materially different from these estimates.

Asset Retirement Obligations

ASC 410, *Asset Retirement and Environmental Obligations* (ASC 410) requires that the fair value of an asset retirement cost, and corresponding liability, should be recorded as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. The Company records asset retirement obligations to reflect the Company's legal obligations related to future plugging and abandonment of its oil and natural gas wells and gas gathering systems and equipment. The Company estimates the expected cash flows associated with the obligation and discounts the amounts using a credit-adjusted, risk-free interest rate. At least annually, the Company reassesses the obligation to determine whether a change in the estimated obligation is necessary. The Company evaluates whether there are indicators that suggest the estimated cash flows underlying the obligation have materially changed. Should these indicators suggest the estimated obligation may have materially changed on an interim basis (quarterly), the Company will accordingly update its assessment. Additional retirement obligations increase the liability associated with new oil and natural gas wells and gas gathering systems and equipment as these obligations are incurred.

401(k) Plan

The Company sponsors a 401(k) tax deferred savings plan, whereby the Company matches a portion of employees' contributions in cash. Participation in the plan is voluntary and all employees of the Company who are 18 years of age are eligible to participate. The Company provided matching contributions of $0.8 million and $2.0 million for the period September 10, 2016 through December 31, 2016 (Successor) and the period January 1, 2016 through September 9, 2016 (Predecessor), respectively. The Company provided matching contributions of $3.8 million and $4.5 million in 2015 and 2014 (Predecessor), respectively. The Company matches employee contributions dollar-for-dollar on the first 10% of an employee's pre-tax earnings, subject to individual IRS limitations.

1. SUMMARY OF SIGNIFICANT EVENTS AND ACCOUNTING POLICIES (Continued)

Recently Issued Accounting Pronouncements

In August 2016, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2016-15, *Statement of Cash Flows (Topic 230)* (ASU 2016-15). For public business entities, ASU 2016-15 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2017 and early adoption is permitted. The areas for simplification in this ASU involve addressing eight specific classification issues in the statement of cash flows. An entity should apply the amendments in this ASU using a retrospective transition method. The Company is in the early stages of assessing the effects of the application of the new guidance.

In March 2016, the FASB issued ASU 2016-09, *Compensation—Stock Compensation* (ASU 2016-09). For public business entities, ASU 2016-09 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016 and early adoption is permitted. The areas for simplification in this ASU involve several aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. Some of the areas for simplification apply only to nonpublic entities. As there are multiple amendments in this ASU, the FASB has issued guidance on how an entity should apply each amendment, either prospectively or retrospectively. The Company adopted ASU 2016-09 on September 9, 2016. See Note 13, *''Stockholders' Equity''* for further details.

In March 2016, the FASB issued ASU 2016-06, *Contingent Put and Call Options in Debt Instruments* (ASU 2016-06). For public business entities, ASU 2016-06 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016 and early adoption is permitted. ASU 2016-06 provides new guidance that simplifies the analysis of whether a contingent put or call option in a debt instrument qualifies as a separate derivative. An entity should apply the amendments in this ASU on a modified retrospective basis to existing debt instruments as of the beginning of the fiscal year for which the amendments are effective. The Company adopted ASU 2016-06 in 2016 resulting in no changes to the accounting for its current debt instruments.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)* (ASU 2016-02). For public business entities, ASU 2016-02 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018 and early adoption is permitted. The FASB issued ASU 2016-02 to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. An entity should apply the amendments in this ASU on a modified retrospective basis. The transition will require application of the new guidance at the beginning of the earliest comparative period presented in the financial statements. The Company is in the early stages of assessing the effects of the application of the new guidance and the financial statement and disclosure impacts. The Company will adopt ASU 2016-02 no later than January 1, 2019.

In September 2015, the FASB issued ASU 2015-16, *Business Combinations—Simplifying the Accounting for Measurement-Period Adjustments* (ASU 2015-16). For public business entities, ASU 2015-16 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015 and early adoption is permitted. The amendments in this ASU require that an acquirer, in a business combination, recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. To simplify the accounting for adjustments made to provisional amounts recognized in a

1. SUMMARY OF SIGNIFICANT EVENTS AND ACCOUNTING POLICIES (Continued)

business combination, the amendments in this ASU eliminate the requirement to retrospectively account for those adjustments, and instead present separately on the face of the income statement or disclose in the footnotes the portion of the amount recorded in current-period earnings by line item that would have been recorded in previous reporting periods. The adoption of ASU 2015-16 did not have a material impact to the Company's financial statements or disclosures.

In February 2015, the FASB issued ASU 2015-02, *Amendments to the Consolidation Analysis* (ASU 2015-02). The amendments in ASU 2015-02 eliminate the previous presumption that a general partner controls a limited partner. ASU 2015-02 is effective for public entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. Early adoption is permitted. Entities may apply the guidance using a modified retrospective approach by recording a cumulative-effect adjustment to equity as of the beginning of the first fiscal year adopted or it may apply the amendment retrospectively. The adoption of ASU 2015-02 did not have an impact on the Company's financial statements or disclosures.

In August 2014, the FASB issued ASU 2014-15, *Presentation of Financial Statements—Going Concern* (ASU 2014-15). ASU 2014-15 is effective for annual reporting periods (including interim periods within those periods) ending after December 15, 2016. Early application is permitted. The amendments in ASU 2014-15 create a new ASC Sub-topic 205-40, *Presentation of Financial Statements—Going Concern* and require management to assess for each annual and interim reporting period if conditions exist that raise substantial doubt about an entity's ability to continue as a going concern. The rule requires various disclosures depending on the facts and circumstances surrounding an entity's ability to continue as a going concern. Effective June 30, 2016, the Company early adopted ASU 2014-15 on a prospective basis.

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers* (ASU 2014-09). ASU 2014-09 states that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The standard provides five steps an entity should apply in determining its revenue recognition. In March 2016, ASU 2014-09 was updated with ASU No. 2016-08, *Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net)* (ASU 2016-08), which provides further clarification on the principal versus agent evaluation. ASU 2014-09 is required to be adopted using either the full retrospective approach, with all prior periods presented adjusted, or the modified retrospective approach, with a cumulative adjustment to retained earnings on the opening balance sheet and is effective for annual reporting periods, and interim periods within that reporting period, after December 15, 2017. Early adoption is not permitted. The Company is in the early stages of assessing the effects of the application of the new guidance and the financial statement and disclosure impacts. The Company will adopt ASU 2014-09 effective January 1, 2018.

2. REORGANIZATION

On June 9, 2016, the Halcón Entities entered into a restructuring support agreement (the Restructuring Support Agreement) with certain holders of the Company's 13% senior secured third lien notes due 2022 (the Third Lien Noteholders), the Company's 8.875% senior unsecured notes due 2021, 9.25% senior unsecured notes due 2022 and 9.75% senior unsecured notes due 2020 (collectively, the Unsecured Noteholders), the holder of the Company's 8% senior unsecured convertible note due 2020

2. REORGANIZATION (Continued)

(the Convertible Noteholder), and certain holders of the Company's 5.75% Series A Convertible Perpetual Preferred Stock. On July 27, 2016, the Halcón Entities filed voluntary petitions for relief under chapter 11 of the United States Bankruptcy Code in the U.S. Bankruptcy Court in the District of Delaware to effect an accelerated prepackaged bankruptcy restructuring as contemplated in the Restructuring Support Agreement. On September 8, 2016, the Bankruptcy Court entered an order confirming the Company's plan of reorganization and on September 9, 2016, the Halcón Entities emerged from chapter 11 bankruptcy.

Upon emergence, pursuant to the terms of the Plan, the following significant transactions occurred:

- the Predecessor Company's financing facility under the Predecessor Credit Agreement was refinanced and replaced with the DIP Facility, which was subsequently converted into the Senior Credit Agreement (refer to Note 7, *"Long-term Debt"* for credit agreement definitions and further details regarding the credit agreements);
- the Predecessor Company's Second Lien Notes (consisting of $700.0 million in aggregate principal amount outstanding of 8.625% senior secured notes due 2020 and $112.8 million in aggregate principal amount outstanding of 12% senior secured notes due 2022) were unimpaired and reinstated;
- the Predecessor Company's Third Lien Notes were cancelled and the Third Lien Noteholders received their pro rata share of 76.5% of the common stock of reorganized Halcón, together with a cash payment of $33.8 million, and accrued and unpaid interest on their notes through May 15, 2016, which interest was paid prior to the chapter 11 bankruptcy filing, in full and final satisfaction of their claims;
- the Predecessor Company's Unsecured Notes were cancelled and the Unsecured Noteholders received their pro rata share of 15.5% of the common stock of reorganized Halcón, together with a cash payment of $37.6 million and warrants to purchase 4% of the common stock of reorganized Halcón (with a four year term and an exercise price of $14.04 per share), and accrued and unpaid interest on their notes through May 15, 2016, which interest was paid prior to the chapter 11 bankruptcy filing, in full and final satisfaction of their claims;
- the Predecessor Company's Convertible Note was cancelled and the Convertible Noteholder received 4% of the common stock of reorganized Halcón, together with a cash payment of $15.0 million and warrants to purchase 1% of the common stock of reorganized Halcón (with a four year term and an exercise price of $14.04 per share), in full and final satisfaction of their claims;
- the general unsecured claims were unimpaired and paid in full in the ordinary course;
- all outstanding shares of the Predecessor Company's Series A Preferred Stock were cancelled and the Preferred Holders received their pro rata share of $11.1 million in cash, in full and final satisfaction of their interests; and
- all of the Predecessor Company's outstanding shares of common stock were cancelled and the common stockholders received their pro rata share of 4% of the common stock of reorganized Halcón, in full and final satisfaction of their interests.

2. REORGANIZATION (Continued)

Each of the foregoing percentages of equity in the reorganized Company were as of September 9, 2016 and subject to dilution from the exercise of the new warrants described above, a management incentive plan and other future issuances of equity securities.

See Note 7, *"Long-term Debt,"* and Note 13, "*Stockholders' Equity*," for further information regarding the Company's Successor and Predecessor debt and equity instruments.

3. FRESH-START ACCOUNTING

Upon the Company's emergence from chapter 11 bankruptcy, the Company qualified for and adopted fresh-start accounting in accordance with the provisions set forth in ASC 852 as (i) the Reorganization Value of the Company's assets immediately prior to the date of confirmation was less than the post-petition liabilities and allowed claims, and (ii) the holders of the existing voting shares of the Predecessor entity received less than 50% of the voting shares of the emerging entity. Refer to Note 2, *"Reorganization,"* for the terms of the Plan. Fresh-start accounting requires the Company to present its assets, liabilities, and equity as if it were a new entity upon emergence from bankruptcy. The new entity is referred to as "Successor" or "Successor Company." However, the Company will continue to present financial information for any periods before adoption of fresh-start accounting for the Predecessor Company. The Predecessor and Successor companies may lack comparability, as required in ASC Topic 205, *Presentation of Financial Statements* (ASC 205). ASC 205 states financial statements are required to be presented comparably from year to year, with any exceptions to comparability clearly disclosed. Therefore, "black-line" financial statements are presented to distinguish between the Predecessor and Successor Companies.

Adopting fresh-start accounting results in a new financial reporting entity with no beginning retained earnings or deficit as of the fresh-start reporting date. Upon the application of fresh-start accounting, the Company allocated the Reorganization Value (the fair value of the Successor Company's total assets) to its individual assets based on their estimated fair values. The Reorganization Value is intended to represent the approximate amount a willing buyer would value the Company's assets immediately after the reorganization.

Reorganization Value is derived from an estimate of Enterprise Value, or the fair value of the Company's long-term debt, stockholders' equity and working capital. The estimated Enterprise Value at the Effective Date is below the midpoint of the Court approved range of $1.6 billion to $1.8 billion, primarily reflecting the decline in forward commodity prices during the period between the Company's analysis performed in advance of the July 2016 chapter 11 bankruptcy filing and the Effective Date. The Enterprise Value was derived from an independent valuation using an asset based methodology of proved reserves, undeveloped acreage, and other financial information, considerations and projections, applying a combination of the income, cost and market approaches as of the fresh-start reporting date of September 9, 2016.

The Company's principal assets are its oil and natural gas properties. For purposes of estimating the fair value of the Company's proved, probable and possible reserves, an income approach was used which estimated fair value based on the anticipated cash flows associated with the Company's reserves, risked by reserve category and discounted using a weighted average cost of capital rate of 10.5% for proved reserves and 12.5% for probable and possible reserves. The proved reserve locations were limited to wells expected to be drilled in the Company's five year development plan. Weighted average commodity prices utilized in the determination of the fair value of oil and natural gas properties were

3. FRESH-START ACCOUNTING (Continued)

$72.30 per barrel of oil, $3.50 per MMBtu of natural gas and $12.00 per barrel of oil equivalent of natural gas liquids, after adjustment for transportation fees and regional price differentials. Base pricing was derived from an average of forward strip prices and analysts' estimated prices.

In estimating the fair value of the Company's unproved acreage that was not included in the valuation of probable and possible reserves, a market approach was used in which a review of recent transactions involving properties in the same geographical location indicated the fair value of the Company's unproved acreage from a market participant perspective.

See further discussion below in the *"Fresh-start accounting adjustments"* for the specific assumptions used in the valuation of the Company's various other assets.

Although the Company believes the assumptions and estimates used to develop Enterprise Value and Reorganization Value are reasonable and appropriate, different assumptions and estimates could materially impact the analysis and resulting conclusions. The assumptions used in estimating these values are inherently uncertain and require judgment.

The following table reconciles the Company's Enterprise Value to the estimated fair value of the Successor's common stock as of September 9, 2016 (in thousands):

	September 9, 2016
Enterprise Value	$ 1,618,888
Plus: Cash	13,943
Less: Fair value of debt	(1,016,160)
Less: Fair value of redeemable noncontrolling interest	(41,070)
Less: Fair value of other long-term liabilities	(4,478)
Less: Fair value of warrants	(16,691)
Fair Value of Successor common stock	$ 554,432

The following table reconciles the Company's Enterprise Value to its Reorganization Value as of September 9, 2016 (in thousands):

	September 9, 2016
Enterprise Value	$1,618,888
Plus: Cash	13,943
Plus: Current liabilities	178,639
Plus: Noncurrent asset retirement obligation	32,156
Reorganization Value of Successor assets	$1,843,626

Condensed Consolidated Balance Sheet

The following illustrates the effects on the Company's consolidated balance sheet due to the reorganization and fresh-start accounting adjustments. The explanatory notes following the table below provide further details on the adjustments, including the Company's assumptions and methods used to

3. FRESH-START ACCOUNTING (Continued)

determine fair value for its assets and liabilities. Amounts included in the table below are rounded to thousands.

	As of September 9, 2016			
	Predecessor Company	Reorganization Adjustments	Fresh-Start Adjustments	Successor Company
Current assets:				
Cash	$ 111,464	$ (97,521)*(1)*	$ —	$ 13,943
Accounts receivable	116,859	—	—	116,859
Receivables from derivative contracts	97,648	—	—	97,648
Restricted cash	17,164	—	—	17,164
Prepaids and other	8,961	—	(1,332)*(7)*	7,629
Total current assets	352,096	(97,521)	(1,332)	253,243
Oil and natural gas properties (full cost method):				
Evaluated	7,712,003	—	(6,497,874)*(8)*	1,214,129
Unevaluated	1,193,259	—	(861,144)*(8)*	332,115
Gross oil and natural gas properties	8,905,262	—	(7,359,018)	1,546,244
Less—accumulated depletion	(6,803,231)	—	6,803,231*(8)*	—
Net oil and natural gas properties	2,102,031	—	(555,787)	1,546,244
Other operating property and equipment:				
Gas gathering and other operating assets	100,079	—	(62,008)*(9)*	38,071
Less—accumulated depreciation	(24,154)	—	24,154*(9)*	—
Net other operating property and equipment	75,925	—	(37,854)	38,071
Other noncurrent assets:				
Receivables from derivative contracts	4,431	—	—	4,431
Funds in escrow and other	1,610	—	27*(10)*	1,637
Total assets	$ 2,536,093	$ (97,521)	$ (594,946)	$1,843,626
Current liabilities:				
Accounts payable and accrued liabilities	$ 160,000	$ 13,688*(2)*	$ —	$ 173,688
Liabilities from derivative contracts	102	—	—	102
Other	414	—	4,435*(11)(12)*	4,849
Total current liabilities	160,516	13,688	4,435	178,639
Long-term debt, net	1,031,114	—	(14,954)*(13)*	1,016,160
Liabilities subject to compromise	2,007,703	(2,007,703)*(3)*	—	—
Other noncurrent liabilities:				
Liabilities from derivative contracts	525	—	—	525
Asset retirement obligations	48,955	—	(16,799)*(12)*	32,156
Other	528	—	3,425*(11)(14)*	3,953
Commitments and contingencies				
Mezzanine equity:				
Redeemable noncontrolling interest	219,891	—	(178,821)*(14)*	41,070
Stockholders' equity:				
Preferred stock (Predecessor)	—	—*(4)*	—	—
Common Stock (Predecessor)	12	(12)*(4)*	—	—
Common Stock (Successor)	—	9*(5)*	—	9
Additional paid-in capital (Predecessor)	3,287,906	(3,287,906)*(4)*	—	—
Additional paid-in capital (Successor)	—	571,114*(5)*	—	571,114
Retained earnings (accumulated deficit)	(4,221,057)	4,613,289*(6)*	(392,232)*(15)*	—
Total stockholders' equity	(933,139)	1,896,494	(392,232)	571,123
Total liabilities and stockholders' equity	$ 2,536,093	$ (97,521)	$ (594,946)	$1,843,626

3. FRESH-START ACCOUNTING (Continued)

Reorganization adjustments

1) The table below details cash payments as of September 9, 2016, pursuant to the terms of the Plan described in Note 2, "*Reorganization*" (in thousands):

Payment to Third Lien Noteholders	$33,826
Payment to Unsecured Noteholders	37,595
Payment to Convertible Noteholder	15,000
Payment to Preferred Holders	11,100
Total Uses	$97,521

2) In connection with the chapter 11 bankruptcy, the Company modified and rejected certain office lease arrangements and paid approximately $3.4 million for these modifications and rejections subsequent to the emergence from chapter 11 bankruptcy. This amount also reflects $10.3 million paid to the Company's restructuring advisors subsequent to the emergence from chapter 11 bankruptcy.

3) Liabilities subject to compromise were as follows (in thousands):

13.0% senior secured third lien notes due 2022	$1,017,970
9.25% senior notes due 2022	37,194
8.875% senior notes due 2021	297,193
9.75% senior notes due 2020	315,535
8.0% convertible note due 2020	289,669
Accrued interest	46,715
Office lease modification and rejection fees	3,427
Liabilities subject to compromise	2,007,703
Fair value of equity and warrants issued to Third Lien Noteholders, Unsecured Noteholders and Convertible Noteholder	(548,947)
Cash payments to Third Lien Noteholders, Unsecured Noteholders and Convertible Noteholder	(86,421)
Office lease modification and rejection fees	(3,427)
Gain on settlement of Liabilities subject to compromise	$1,368,908

4) Reflects the cancellation of Predecessor equity, as follows (in thousands):

Predecessor Company stock	$3,287,918
Fair value of equity issued to Predecessor common stockholders	(22,176)
Cash payment to Preferred Holders	(11,100)
Cancellation of Predecessor Company equity	$3,254,642

5) Reflects the issuance of Successor equity. In accordance with the Plan, the Successor Company issued 3.6 million shares of common stock to the Predecessor Company's existing common stockholders, 68.8 million shares of common stock to the Third Lien Noteholders, 14.0 million shares of common stock to the Unsecured Noteholders, and 3.6 million shares of common stock to

3. FRESH-START ACCOUNTING (Continued)

the Convertible Noteholder. This amount is subject to dilution by warrants issued to the Unsecured Noteholders and the Convertible Noteholder totaling 4.7 million shares with an exercise price of $14.04 per share and a term of four years. The fair value of the warrants was estimated at $3.52 per share using a Black-Scholes-Merton valuation model.

6) The table below reflects the cumulative effect of the reorganization adjustments discussed above (in thousands):

Gain on settlement of Liabilities subject to compromise	$1,368,908
Accrued reorganization items	(10,261)
Cancellation of Predecessor Company equity	3,254,642
Net impact to retained earnings (accumulated deficit)	$4,613,289

Fresh-start accounting adjustments

7) Reflects the reclassification of tubulars and well equipment to "*Oil and natural gas properties*."

8) In estimating the fair value of its oil and natural gas properties, the Company used a combination of the income and market approaches. For purposes of estimating the fair value of the Company's proved, probable and possible reserves, an income approach was used which estimated fair value based on the anticipated cash flows associated with the Company's reserves, risked by reserve category and discounted using a weighted average cost of capital rate of 10.5% for proved reserves and 12.5% for probable and possible reserves. The proved reserve locations were limited to wells expected to be drilled in the Company's five year development plan. Weighted average commodity prices utilized in the determination of the fair value of oil and natural gas properties were $72.30 per barrel of oil, $3.50 per MMBtu of natural gas and $12.00 per barrel of natural gas liquids, after adjustment for transportation fees and regional price differentials. Base pricing was derived from an average of forward strip prices and analysts' estimated prices.

In estimating the fair value of the Company's unproved acreage that was not included in the valuation of probable and possible reserves, a market approach was used in which a review of recent transactions involving properties in the same geographical location indicated the fair value of the Company's unproved acreage from a market participant perspective.

9) In estimating the fair value of its gas gathering and other operating assets, the Company used a combination of the income, cost, and market approaches.

For purposes of estimating the fair value of its gas gathering assets, an income approach was used that estimated future cash flows associated with the assets over the remaining useful lives. The valuation included such inputs as estimated future production, gathering and compression revenues, and operating expenses that were discounted at a weighted average cost of capital rate of 9.5%.

For purposes of estimating the fair value of its other operating assets, the Company used a combination of the market and cost approaches. A market approach was relied upon to value land and computer equipment, and in this valuation approach, recent transactions of similar assets were utilized to determine the value from a market participant perspective. For the remaining other operating assets, a cost approach was used. The estimation of fair value under the cost approach

3. FRESH-START ACCOUNTING (Continued)

was based on current replacement costs of the assets, less depreciation based on the estimated economic useful lives of the assets and age of the assets.

10) Reflects the adjustment of the Company's equity method investment in SBE Partners, L.P. to fair value based on an income approach, which calculated the discounted cash flows of the Company's share of the partnership's interest in oil and gas proved reserves. The anticipated cash flows of the reserve were risked by reserve category and discounted at 10.5%. Weighted average commodity prices utilized in the determination of the fair value of oil and natural gas properties were $72.30 per barrel of oil, $3.50 per MMBtu of natural gas and $12.00 per barrel of oil equivalent of natural gas liquids, after adjustment for transportation fees and regional price differentials. Base pricing was derived from an average of forward strip prices and analysts' estimated prices.

11) Records an intangible liability of approximately $8.3 million, $4.5 million of which was recorded as current, to adjust the Company's active rig contract to fair value at September 9, 2016. The intangible liability will be amortized over the remaining life of the contract through July 2018.

12) Reflects the adjustment of asset retirement obligations to fair value using estimated plugging and abandonment costs as of September 9, 2016, adjusted for inflation and then discounted at the appropriate credit-adjusted risk free rate ranging from 5.5% to 6.6% depending on the life of the well. The fair value of asset retirement obligations was estimated at $32.5 million, approximately $0.3 million of which was recorded as current. Refer to Note 10, *"Asset Retirement Obligations"* for further details of the Company's asset retirement obligations.

13) Reflects the adjustment of the 2020 Second Lien Notes and the 2022 Second Lien Notes to fair value. The fair value estimate was based on quoted market prices from trades of such debt on September 9, 2016. Refer to Note 7, *"Long-term Debt"* for definitions of and further information regarding the 2020 Second Lien Notes and 2022 Second Lien Notes.

14) Reflects the adjustment of the Company's redeemable noncontrolling interest and related embedded derivative of HK TMS, LLC to fair value. The fair value of the redeemable noncontrolling interest was estimated at $41.1 million and the embedded derivative was estimated at zero. For purposes of estimating the fair values, an income approach was used that estimated fair value based on the anticipated cash flows associated with HK TMS, LLC's proved reserves, risked by reserve category and discounted using a weighted average cost of capital rate of 12.5%. The value of the redeemable noncontrolling interest was further reduced by a probability factor of the potential assignment of the common shares of HK TMS, LLC to Apollo Global Management, which occurred subsequent to the fresh-start date. Refer to Note 5, *"Divestitures,"* for further information regarding the divestiture of HK TMS, LLC on September 30, 2016.

15) Reflects the cumulative effect of the fresh-start accounting adjustments discussed above.

Reorganization Items

Reorganization items represent (i) expenses or income incurred subsequent to the Petition Date as a direct result of the Plan, (ii) gains or losses from liabilities settled, and (iii) fresh-start accounting

3. FRESH-START ACCOUNTING (Continued)

adjustments and are recorded in "*Reorganization items*" in the Company's consolidated statements of operations. The following table summarizes the net reorganization items (in thousands):

	Successor	Predecessor
	Period from September 10, 2016 through December 31, 2016	Period from January 1, 2016 through September 9, 2016
Gain on settlement of Liabilities subject to compromise	$ —	$1,368,908
Fresh start adjustments	—	(392,232)
Reorganization professional fees and other	(2,049)	(30,287)
Write-off debt discounts/premiums and debt issuance costs	—	(32,667)
Gain (loss) on reorganization items	$(2,049)	$ 913,722

4. RESTRUCTURING

In 2016 and 2015, the Predecessor Company had reductions in its workforce due to the decrease in drilling and developmental activities planned for the years. Consequently, in 2016 and 2015 the Predecessor Company incurred approximately $5.2 million and $2.9 million, respectively, in severance costs and accelerated stock-based compensation expense related to the termination of certain employees during the year. These costs were recorded in "*Restructuring*" on the consolidated statements of operations.

5. DIVESTITURES

HK TMS, LLC

On September 30, 2016, certain wholly-owned subsidiaries of the Successor Company executed an Assignment and Assumption Agreement with an affiliate of Apollo Global Management (Apollo) pursuant to which Apollo acquired one hundred percent (100%) of the common shares (the Membership Interests) of HK TMS, LLC (HK TMS), which transaction is referred to as the HK TMS Divestiture. HK TMS was previously a wholly-owned subsidiary and held all of the Successor Company's oil and natural gas properties in the Tuscaloosa Marine Shale (TMS). In exchange for the assignment of the Membership Interests, Apollo assumed all obligations relating to the Membership Interests, which were previously classified as *"Mezzanine Equity"* on the consolidated balance sheets of HK TMS, from and after such date. Refer to Note 12, *"Mezzanine Equity"* for further details of the accounting considerations for HK TMS.

Effective with the HK TMS Divestiture, all of the Successor Company's existing 100% owned subsidiaries are joint and several, full and unconditional guarantors of its long-term debt obligations and the Successor Company has no independent assets or operations. As a consequence, the Successor Company has discontinued the presentation of condensed consolidating financial statements which separately presented HK TMS's non-guarantor financial position, statements of operations and statements of cash flows.

5. DIVESTITURES (Continued)

East Texas Assets

On May 9, 2014, the Predecessor Company completed the divestiture of certain non-core assets in East Texas (the East Texas Assets) to a privately-owned company for a total sales price of $424.5 million after closing adjustments for (i) operating expenses, capital expenditures and revenues between the effective date and the closing date, (ii) title and environmental defects, and (iii) other purchase price adjustments customary in oil and gas purchase and sale agreements. The effective date of the transaction was April 1, 2014. Proceeds from the sale were recorded as a reduction to the carrying value of the Predecessor Company's full cost pool with no gain or loss recorded.

6. OIL AND NATURAL GAS PROPERTIES

Oil and natural gas properties as of December 31, 2016 (Successor) and 2015 (Predecessor) consisted of the following (in thousands):

	Successor	Predecessor
	December 31, 2016	December 31, 2015
Subject to depletion	$1,269,034	$ 7,060,721
Not subject to depletion:		
Exploration and extension wells in progress	5,159	55,126
Other capital costs:		
Incurred in 2016(1)	311,280	—
Incurred in 2015	—	130,911
Incurred in 2014	—	242,788
Incurred in 2013 and prior	—	1,212,531
Total not subject to depletion	316,439	1,641,356
Gross oil and natural gas properties	1,585,473	8,702,077
Less accumulated depletion	(465,849)	(5,933,688)
Net oil and natural gas properties	$1,119,624	$ 2,768,389

(1) *In 2016, with the application of fresh-start accounting, the Company's unevaluated properties were recorded at fair value.*

The Company uses the full cost method of accounting for its investment in oil and natural gas properties. Under this method of accounting, all costs of acquisition, exploration and development of oil and natural gas reserves (including such costs as leasehold acquisition costs, geological expenditures, dry hole costs, tangible and intangible development costs and direct internal costs) are capitalized as the cost of oil and natural gas properties when incurred. To the extent capitalized costs of evaluated oil and natural gas properties, net of accumulated depletion, exceed the discounted future net revenues of proved oil and natural gas reserves, net of deferred taxes, such excess capitalized costs are charged to expense.

With the adoption of fresh-start accounting, the Company recorded its oil and natural gas properties at fair value as of September 9, 2016. The Company's evaluated and unevaluated properties

6. OIL AND NATURAL GAS PROPERTIES (Continued)

were assigned values of $1.2 billion and $332.1 million, respectively. Refer to Note 3, *"Fresh-start Accounting,"* for a discussion of the valuation approach used.

Additionally, the Company assesses all properties classified as unevaluated property on a quarterly basis for possible impairment or reduction in value. The Company assesses properties on an individual basis or as a group, if properties are individually insignificant. The assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to depletion and the full cost ceiling test limitation. In March 2016, the Predecessor Company transferred the remaining unevaluated Utica and TMS properties of approximately $330.4 million and $74.8 million, respectively, to the full cost pool. For the quarter ended March 31, 2016, management concluded that it was no longer probable that capital would be available or approved to continue exploratory drilling activities in the Predecessor Company's Utica or TMS acreage positions in advance of the related lease expirations due to the Predecessor Company's evaluation of strategic alternatives to reduce its debt and preserve liquidity in light of continued low commodity prices, together with a reduction of the Predecessor Company's exploration department and the Predecessor Company's intent to expend capital only on its most economical and proven areas. During the three months ended December 31, 2014, the Predecessor Company also transferred $211.5 million of unevaluated property costs to the full cost pool related to certain non-core areas of the Utica and TMS plays. These costs pertain to acreage that the Predecessor Company did not plan to develop, at the time of evaluation for impairment, in light of the downtrend in oil prices which rendered certain areas to be deemed uneconomical and/or non-strategic.

Investments in unevaluated oil and natural gas properties and exploration and development projects for which depletion expense is not currently recognized, and for which exploration or development activities are in progress, qualify for interest capitalization. The Predecessor Company determined capitalized interest by multiplying the Predecessor Company's weighted-average borrowing cost on debt by the average amount of qualifying costs incurred that were excluded from the full cost pool; however, the amount of capitalized interest cannot exceed the amount of gross interest expense incurred in any given period. The capitalized interest amounts were recorded as additions to unevaluated oil and natural gas properties on the consolidated balance sheets. As the costs excluded were transferred to the full cost pool, the associated capitalized interest was also transferred to the full cost pool. For the period from January 1, 2016 through September 9, 2016 (Predecessor) and the year ended December 31, 2015 (Predecessor), the Company capitalized interest costs of $68.2 million and $112.7 million, respectively. The Successor Company's policy on the capitalization of interest establishes thresholds for the determination of a development project for the purpose of interest capitalization.

6. OIL AND NATURAL GAS PROPERTIES (Continued)

The ceiling test value of the Company's reserves was calculated based on the following prices:

	West Texas Intermediate (per barrel)(1)	Henry Hub (per MMBtu)(1)
December 31, 2016	$42.75	$2.481
December 31, 2015	50.28	2.587
December 31, 2014	94.99	4.350

(1) *Unweighted average of the first day of the 12-months ended spot price, adjusted by lease or field for quality, transportation fees and market differentials.*

The Company's net book value of oil and natural gas properties at March 31, June 30 and September 30, 2016 exceeded the ceiling amount. The Company recorded full cost ceiling test impairments before income taxes of $420.9 million ($268.1 million after taxes, before valuation allowance) for the period of September 10, 2016 through September 30, 2016 (Successor) and $754.8 million ($478.2 million after taxes, before valuation allowance) for the six months ended June 30, 2016 (Predecessor). The impairment at September 30, 2016 reflects the differences between the first day of the month average prices for the preceding twelve months required by Regulation S-X, Rule 4-10 and ASC 932 in calculating the ceiling test and the forward-looking prices required by ASC 852 to estimate the fair value of the Company's oil and natural gas properties on the fresh-start reporting date of September 9, 2016. The ceiling test impairments at March 31, 2016 and June 30, 2016, were driven by decreases in the first-day-of-the-month 12-month average prices for crude oil used in the ceiling test calculations since December 31, 2015. The impairment at March 31, 2016 also reflects the transfer of the remaining unevaluated Utica and TMS properties as discussed further above.

The Predecessor Company's net book value of oil and natural gas properties at March 31, June 30, September 30 and December 31, 2015 exceeded the ceiling amount. The Predecessor Company recorded a full cost ceiling test impairment before income taxes of $2.6 billion ($1.7 billion after taxes, before valuation allowance) for the year ended December 31, 2015. The impairment for the year ended December 31, 2015 (Predecessor) was driven by decreases in the first-day-of-the-month average prices for crude oil used in the ceiling test calculations from $94.99 per barrel at December 31, 2014 to $50.28 per barrel at December 31, 2015.

The Predecessor Company's net book value of oil and natural gas properties at March 31 and December 31, 2014 exceeded the ceiling amount. The Predecessor Company recorded a full cost ceiling test impairment before income taxes of $239.7 million ($151.4 million after taxes) for the year ended December 31, 2014. The impairment for the year ended December 31, 2014 (Predecessor) primarily relates to non-routine transfers of unevaluated properties to the full cost pool, due to the Predecessor Company's shift in drilling, away from the non-strategic areas of the Utica and TMS until economics and return on investment improve, which would include a combination of lower drilling and completion costs and higher commodity prices.

The Company recorded the full cost ceiling test impairments in *"Full cost ceiling impairment"* in the Company's consolidated statements of operations and in *"Accumulated depletion"* in the Company's consolidated balance sheets.

6. OIL AND NATURAL GAS PROPERTIES (Continued)

Changes in commodity prices, production rates, levels of reserves, future development costs, transfers of unevaluated properties, capital spending, and other factors will determine the Company's actual ceiling test calculation and impairment analyses in future periods.

7. LONG-TERM DEBT

Long-term debt as of December 31, 2016 (Successor) and 2015 (Predecessor) consisted of the following (in thousands):

	Successor	Predecessor
	December 31, 2016	December 31, 2015
Successor senior revolving credit facility	$186,000	$ —
Predecessor senior revolving credit facility	—	62,000
8.625% senior secured second lien notes due 2020[(1)]	672,613	687,797
12.0% senior secured second lien notes due 2022[(1)]	106,040	111,598
13.0% senior secured third lien notes due 2022[(3)(8)]	—	1,009,585
9.25% senior notes due 2022[(4)(8)]	—	51,887
8.875% senior notes due 2021[(5)(8)]	—	347,671
9.75% senior notes due 2020[(6)(8)]	—	336,470
8.0% convertible note due 2020[(7)(8)]	—	266,629
	$964,653	$2,873,637

(1) Amount is net of a $27.4 million unamortized discount at December 31, 2016 (Successor). Amount is net of $12.2 million unamortized debt issuance costs at December 31, 2015 (Predecessor). On February 16, 2017, the Company repurchased approximately 41% of the outstanding aggregate principal amount of the 2020 Second Lien Notes with proceeds from the issuance of its new 6.75% senior unsecured notes due 2025. Refer to Note 17, "Subsequent Events," for further details.

(2) Amount is net of a $6.8 million unamortized discount at December 31, 2016 (Successor). Amount is net of $1.2 million unamortized debt issuance costs at December 31, 2015 (Predecessor).

(3) Amount is net of $8.4 million unamortized debt issuance costs at December 31, 2015 (Predecessor).

(4) Amount is net of $0.8 million unamortized debt issuance costs at December 31, 2015 (Predecessor).

(5) Amount is net of a $1.0 million unamortized discount at December 31, 2015 (Predecessor) related to the issuance of the original 2021 Notes. The unamortized premium related to the additional 2021 Notes was approximately $5.5 million at December 31, 2015 (Predecessor). Amount is net of $5.8 million unamortized debt issuance costs at December 31, 2015 (Predecessor).

7. LONG-TERM DEBT (Continued)

(6) *Amount is net of a $1.9 million unamortized discount at December 31, 2015 (Predecessor) related to the issuance of the original 2020 Notes. The unamortized premium related to the additional 2020 Notes was approximately $2.6 million at December 31, 2015 (Predecessor). Amount is net of $4.3 million unamortized debt issuance costs at December 31, 2015 (Predecessor).*

(7) *Amount is net of a $23.0 million unamortized discount at December 31, 2015 (Predecessor).*

(8) *These notes were cancelled on September 9, 2016 upon emergence from chapter 11 bankruptcy. Contractual interest expense not accrued or recorded on pre-petition debt as a result of the chapter 11 bankruptcy amounted to $25.2 million for the period from July 27, 2016 to September 9, 2016.*

Successor Senior Revolving Credit Facility

On the Effective Date, the Company entered into a senior secured revolving credit agreement (the Senior Credit Agreement) with JPMorgan Chase Bank, N.A., as administrative agent, and certain other financial institutions party thereto, as lenders, which refinanced the DIP facility, discussed below. The Senior Credit Agreement provides for a $1.5 billion senior secured reserve-based revolving credit facility with a current borrowing base of $600.0 million. The maturity date of the Senior Credit Agreement is the earlier of (i) July 28, 2021 and (ii) the 120th day prior to the February 1, 2020 stated maturity date of the Company's 2020 Second Lien Notes (defined below), if such notes have not been refinanced, redeemed or repaid in full on or prior to such 120th day. The first borrowing base redetermination will be on May 1, 2017 and redeterminations will occur semi-annually thereafter, with the lenders and the Company each having the right to one interim unscheduled redetermination between any two consecutive semi-annual redeterminations. The borrowing base takes into account the estimated value of the Company's oil and natural gas properties, proved reserves, total indebtedness, and other relevant factors consistent with customary oil and natural gas lending criteria. Amounts outstanding under the Senior Credit Agreement bear interest at specified margins over the base rate of 1.75% to 2.75% for ABR-based loans or at specified margins over LIBOR of 2.75% to 3.75% for Eurodollar-based loans. These margins fluctuate based on the Company's utilization of the facility. The Company may elect, at its option, to prepay any borrowings outstanding under the Senior Credit Agreement without premium or penalty (except with respect to any break funding payments which may be payable pursuant to the terms of the Senior Credit Agreement). Additionally, if the Company has outstanding borrowings or letters of credit or reimbursement obligations in respect of letters of credit and the Consolidated Cash Balance (as defined in the Senior Credit Agreement) exceeds $100.0 million as of the close of business on the most recently ended business day, the Company may also be required to make mandatory prepayments.

Amounts outstanding under the Senior Credit Agreement are guaranteed by certain of the Company's direct and indirect subsidiaries and secured by a security interest in substantially all of the assets of the Company and its subsidiaries.

The Senior Credit Agreement also contains certain financial covenants, including the maintenance of (i) a Total Net Indebtedness Leverage Ratio (as defined in the Senior Credit Agreement) not to exceed 4.75:1.00 initially, determined as of each four fiscal quarter periods and commencing with the fiscal quarter ending September 30, 2016, stepping down to 4.50:1.00 and 4.00:1.00 on September 30, 2017 and March 31, 2019, respectively, and (ii) a Current Ratio (as defined in the Senior Credit

7. LONG-TERM DEBT (Continued)

Agreement) not to be less than 1.00:1.00, commencing with the fiscal quarter ending December 31, 2016. At December 31, 2016, the Company was in compliance with the financial covenants under the Senior Credit Agreement.

The Senior Credit Agreement also contains certain events of default, including non-payment; breaches of representations and warranties; non-compliance with covenants or other agreements; cross-default to material indebtedness; judgments; change of control; and voluntary and involuntary bankruptcy.

At December 31, 2016 (Successor), the Company had approximately $186.0 million of indebtedness outstanding, approximately $6.7 million letters of credit outstanding and approximately $407.3 million of borrowing capacity available under the Senior Credit Agreement.

DIP Facility

In connection with the chapter 11 bankruptcy proceedings, the Predecessor Company entered into a commitment letter pursuant to which the lenders party thereto committed to provide, subject to certain conditions, a $600.0 million debtor-in-possession senior secured, super-priority revolving credit facility (the DIP Facility) and to replace it upon emergence with a $600.0 million senior secured reserve-based revolving credit facility, discussed above. Proceeds from the DIP Facility were used to refinance borrowings under the Predecessor Credit Agreement (defined below). Availability under the DIP Facility was $500.0 million upon interim approval by the Bankruptcy Court, and rose to $600.0 million upon entry of a final order. The DIP Facility was refinanced by the Senior Credit Agreement, upon emergence from chapter 11 bankruptcy. Loans under the DIP Facility bore interest at specified margins over the base rate of 1.75% to 2.75% for ABR-based loans or at specified margins over LIBOR of 2.75% to 3.75% for Eurodollar-based loans. These margins fluctuated based on the utilization of the DIP Facility.

Predecessor Senior Revolving Credit Facility

On February 8, 2012, the Predecessor Company entered into a senior secured revolving credit agreement (the Predecessor Credit Agreement) with JPMorgan Chase Bank, N.A., as administrative agent, and the other lenders party thereto. The Predecessor Credit Agreement provided for a $1.5 billion facility with a borrowing base of $700.0 million. Amounts outstanding under the Predecessor Credit Agreement bore interest at specified margins over the base rate of 1.50% to 2.50% for ABR-based loans or at specified margins over LIBOR of 2.50% to 3.50% for Eurodollar-based loans. These margins fluctuated based on the utilization of the facility. Proceeds from the DIP Facility were used to refinance borrowings under the Company's Predecessor Credit Agreement.

8.625% Senior Secured Second Lien Notes

On May 1, 2015 (Predecessor), the Company issued $700 million aggregate principal amount of its 8.625% second lien senior secured notes due 2020 (the 2020 Second Lien Notes) in a private offering. The 2020 Second Lien Notes were issued at par. The net proceeds from the sale of the 2020 Second Lien Notes were approximately $686.2 million (after deducting offering fees and expenses).

The 2020 Second Lien Notes bear interest at a rate of 8.625% per annum, payable semi-annually on February 1 and August 1 of each year. The 2020 Second Lien Notes will mature on February 1,

7. LONG-TERM DEBT (Continued)

2020. The 2020 Second Lien Notes are secured by second-priority liens on substantially all of the Company's and its guarantors' assets to the extent such assets secure the Company's Senior Credit Agreement, its 2022 Second Lien Notes (defined below) (the Collateral). Pursuant to the terms of an Intercreditor Agreement, dated May 1, 2015 as amended by those certain Priority Confirmation Joinders, dated September 10, 2015 and December 21, 2015, in connection with the issuance of the Third Lien Notes and the 2022 Second Lien Notes (discussed below), respectively (the Intercreditor Agreement), the security interest in those assets that secure the 2020 Second Lien Notes and the guarantees are contractually subordinated to liens that secure the Company's Senior Credit Agreement and certain other permitted indebtedness. Consequently, the 2020 Second Lien Notes and the guarantees are effectively subordinated to the Senior Credit Agreement and such other indebtedness to the extent of the value of such assets. The Collateral does not include any of the assets of the Company's future unrestricted subsidiaries. In accordance with the terms of the Plan, the 2020 Second Lien Notes were unimpaired and reinstated upon the Company's emergence from the chapter 11 bankruptcy.

As discussed in Note 3, *"Fresh-start Accounting,"* on September 9, 2016, the Company adjusted the 2020 Second Lien Notes to fair value of $679.0 million by recording a discount of $21.0 million to be amortized over the remaining life of the 2020 Second Lien Notes, using the effective interest method.

The 2020 Second Lien Notes are governed by an Indenture, dated as of May 1, 2015, by and among the Company, certain subsidiaries of the Company (the Guarantors) and U.S. Bank National Association, as Trustee, (the Trustee), which contains affirmative and negative covenants that, among other things, limit the ability of the Company and the Guarantors to incur indebtedness; purchase or redeem stock or subordinated indebtedness; make investments; create liens; enter into transactions with affiliates; sell assets; refinance certain indebtedness; merge with or into other companies or transfer substantially all of their assets; and, in certain circumstances, to pay dividends or make other distributions on stock. The indenture also contains customary events of default. Upon the occurrence of certain events of default, the Trustee or the holders of the 2020 Second Lien Notes may declare all outstanding 2020 Second Lien Notes to be due and payable immediately. The 2020 Second Lien Notes are fully and unconditionally guaranteed on a senior basis by the Guarantors and by certain future subsidiaries of the Company.

On September 28, 2016 (Successor), the Company, each of its guarantors and U.S. Bank National Association, as trustee, entered into a supplemental indenture (the 2020 Second Lien Note Supplemental Indenture) to the Indenture dated as of May 1, 2015 with respect to the Company's 2020 Second Lien Notes (the 2020 Second Lien Note Indenture). The 2020 Second Lien Note Supplemental Indenture amended the 2020 Second Lien Note Indenture to modify the incurrence of indebtedness, lien and restricted payments covenants. The 2020 Second Lien Note Supplemental Indenture became operative upon the consummation of the consent solicitation on September 30, 2016. The Company paid an aggregate consent fee of approximately $8.6 million to holders of the 2020 Second Lien Notes and recorded an additional discount of approximately $8.6 million. The remaining unamortized discount was $27.4 million at December 31, 2016.

On February 16, 2017 (Successor), the Company paid approximately $303.5 million for approximately $289.2 million principal amount of 2020 Second Lien Notes, a make-whole premium of $13.2 million plus accrued and unpaid interest of approximately $1.1 million to repurchase such notes pursuant to a tender offer and issued a redemption notice to redeem the remaining 2020 Second Lien

7. LONG-TERM DEBT (Continued)

Notes. The remaining $410.8 million aggregate principal amount of 2020 Second Lien Notes will be repurchased through the guaranteed delivery procedures or redeemed at a price of 104.313% of the principal amount thereof, plus accrued and unpaid interest to, but not including, the redemption date. The redemption date is expected to be March 20, 2017. The repurchase and redemption of the 2020 Second Lien Notes will be funded with proceeds from the issuance of $850.0 million in new 6.75% senior unsecured notes due 2025. See Note 17, *"Subsequent Events,"* for further details.

12.0% Senior Secured Second Lien Notes

On December 21, 2015 (Predecessor), the Company completed the issuance of approximately $112.8 million aggregate principal amount of new 12.0% second lien senior secured notes due 2022 (the 2022 Second Lien Notes) in exchange for approximately $289.6 million principal amount of its then outstanding senior unsecured notes, consisting of $116.6 million principal amount of its 9.75% senior notes due 2020, $137.7 million principal amount of its 8.875% senior notes due 2021 and $35.3 million principal amount of its 9.25% senior notes due 2022. At closing, the Predecessor Company paid all accrued and unpaid interest since the respective interest payment dates of the unsecured notes surrendered in the exchange. The Predecessor Company recorded the issuance of the 2022 Second Lien Notes at par value and also recognized a $174.5 million net gain on the extinguishment of debt, as a $176.7 million gain on the exchanges was partially offset by the write-down of $2.2 million associated with related issuance costs and discounts and premiums for the respective notes. The net gain was recorded in *"Gain (loss) on extinguishment of debt"* in the consolidated statements of operations.

Interest on the 2022 Second Lien Notes accrues at a rate of 12.0% per annum, payable semi-annually on February 15 and August 15 of each year. The 2022 Second Lien Notes will mature on February 15, 2022. The 2022 Second Lien Notes are secured by second-priority liens on the Collateral. Pursuant to the terms of the Intercreditor Agreement, dated December 21, 2015, the security interest in the Collateral securing the 2022 Second Lien Notes and the guarantees are contractually equal with the liens that secure the 2020 Second Lien Notes and contractually subordinated to liens that secure the Company's Senior Credit Agreement and certain other permitted indebtedness. Consequently, the 2022 Second Lien Notes and the guarantees are effectively subordinated to the Senior Credit Agreement and such other indebtedness and effectively equal to the 2020 Second Lien Notes, in each case to the extent of the value of the Collateral. In accordance with the terms of the Plan, the 2022 Second Lien Notes were unimpaired and reinstated upon the Company's emergence from chapter 11 bankruptcy.

As discussed in Note 3, *"Fresh-start Accounting,"* on September 9, 2016, the Company adjusted the 2022 Second Lien Notes to fair value of $107.2 million by recording a discount of $5.7 million to be amortized over the remaining life of the 2022 Second Lien Notes, using the effective interest method.

On September 28, 2016 (Successor), the Company, each of its guarantors and U.S. Bank National Association, as trustee, entered into a supplemental indenture (the 2022 Second Lien Note Supplemental Indenture) to the Indenture dated as of December 21, 2015 with respect to the Company's 2022 Second Lien Notes (the 2022 Second Lien Note Indenture). The 2022 Second Lien Note Supplemental Indenture amended the 2022 Second Lien Note Indenture to modify the incurrence of indebtedness, lien and restricted payments covenants. The 2022 Second Lien Note Supplemental Indenture became operative upon the consummation of the consent solicitation on September 30, 2016. The Company paid an aggregate consent fee of approximately $1.4 million to holders of the 2022 Second Lien Notes and recorded an additional discount of approximately $1.4 million. The remaining unamortized discount was $6.8 million at December 31, 2016.

7. LONG-TERM DEBT (Continued)

At any time prior to August 15, 2018, the Company may redeem the 2022 Second Lien Notes, in whole or in part, at a redemption price equal to 100% of their principal amount plus a make-whole premium, together with accrued and unpaid interest, if any, to the redemption date. The 2022 Second Lien Notes will be redeemable, in whole or in part, on or after August 15, 2018 at redemption prices equal to the principal amount multiplied by the percentage set forth below, plus accrued and unpaid interest:

Year	Percentage
2018	112.000
2019	106.000
2020 and thereafter	100.000

Additionally, the Company may redeem up to 35% of the 2022 Second Lien Notes on or prior to August 15, 2018 for a redemption price of 112.000% of the principal amount thereof, plus accrued and unpaid interest, utilizing net cash proceeds from certain equity offerings. In addition, upon a change of control of the Company, holders of the 2022 Second Lien Notes will have the right to require the Company to repurchase all or any part of their 2022 Second Lien Notes for cash at a price equal to 101% of the aggregate principal amount of the 2022 Second Lien Notes repurchased, plus any accrued and unpaid interest.

The 2022 Second Lien Notes were issued in accordance with exemptions from the registration requirements of the Securities Act of 1933, as amended afforded by Rule 144A and Regulation S under the Securities Act.

13.0% Senior Secured Third Lien Notes

On September 10, 2015, the Predecessor Company issued approximately $1.02 billion aggregate principal amount of new 13.0% senior secured third lien notes due 2022 (the Third Lien Notes) in a private placement in exchange for approximately $497.2 million principal amount of its then outstanding 9.75% senior notes due 2020, $774.7 million principal amount of its then outstanding 8.875% senior notes due 2021 and $294.4 million principal amount of its then outstanding 9.25% senior notes due 2022 in privately negotiated transactions with certain holders of its senior unsecured notes. The Predecessor Company recorded the issuance of the Third Lien Notes at par and also recognized a $535.1 million net gain on the extinguishment of debt, as a $548.2 million gain on the exchanges was partially offset by the write-down of $13.1 million associated with related issuance costs and discounts and premiums for the respective notes. The net gain was recorded in *"Gain (loss) on extinguishment of debt"* in the consolidated statements of operations for the three months ended September 30, 2015 (Predecessor).

On September 9, 2016, upon emergence from chapter 11 bankruptcy, the Third Lien Notes were cancelled. Refer to Note 2, *"Reorganization,"* for further details.

9.25% Senior Notes

On August 13, 2013, the Predecessor Company issued at par $400.0 million aggregate principal amount of 9.25% senior notes due 2022 (the 2022 Notes). The net proceeds from the offering were approximately $392.1 million (after deducting offering fees and expenses). During the first quarter of

7. LONG-TERM DEBT (Continued)

2016, the Predecessor Company repurchased $15.5 million principal amount of 2022 Notes for cash at prevailing market prices at the time of the transactions and recognized an $11.1 million net gain on the extinguishment of debt.

On September 9, 2016, upon emergence from chapter 11 bankruptcy, the 2022 Notes were cancelled. Refer to Note 2, *"Reorganization,"* for further details.

8.875% Senior Notes

On November 6, 2012, the Predecessor Company issued $750.0 million aggregate principal amount of its 8.875% senior notes due 2021 (the 2021 Notes), at a price to the initial purchasers of 99.247% of par. The net proceeds from the offering were approximately $725.6 million (after deducting offering fees and expenses). On January 14, 2013, the Predecessor Company issued an additional $600.0 million aggregate principal amount of the 2021 Notes at a price to the initial purchasers of 105% of par. The net proceeds from the sale of the additional 2021 Notes were approximately $619.5 million (after offering fees and expenses).

During the first quarter of 2016, the Predecessor Company repurchased $51.8 million principal amount of the 2021 Notes for cash at prevailing market prices at the time of the transactions and recognized a $47.5 million net gain on the extinguishment of debt.

On September 9, 2016, upon emergence from chapter 11 bankruptcy, the 2021 Notes were cancelled. Refer to Note 2, *"Reorganization,"* for further details.

9.75% Senior Notes

On July 16, 2012, the Predecessor Company issued $750.0 million aggregate principal amount of 9.75% senior notes due 2020 issued at 98.646% of par (the 2020 Notes). The net proceeds from the offering were approximately $723.1 million (after deducting offering fees and expenses). On December 19, 2013, the Predecessor Company issued an additional $400.0 million aggregate principal amount of the 2020 Notes at a price to the initial purchasers of 102.750% of par. The net proceeds from the sale of the additional 2020 Notes were approximately $406.3 million (after deducting offering fees and expenses).

During the first quarter of 2016, the Predecessor Company repurchased $24.5 million principal amount of the 2020 Notes for cash at prevailing market prices at the time of the transactions and recognized a $22.8 million net gain on the extinguishment of debt.

On September 9, 2016, upon emergence from chapter 11 bankruptcy, the 2020 Notes were cancelled. Refer to Note 2, *"Reorganization,"* for further details.

8.0% Convertible Note

On February 8, 2012, the Predecessor Company issued to HALRES, LLC (HALRES), a note in the principal amount of $275.0 million due 2017 (the Convertible Note) together with five year warrants (February 2012 Warrants) for an aggregate purchase price of $275.0 million. On March 9, 2015, the Predecessor Company entered into an amendment (the HALRES Note Amendment) to its Convertible Note, which extended the maturity date of the Convertible Note by three years and adjusted the conversion price of the Convertible Note from $22.50 per share to $12.20 per share. The

7. LONG-TERM DEBT (Continued)

Predecessor Company accounted for the HALRES Note Amendment as a debt extinguishment and recorded a net gain of $7.3 million in *"Gain (loss) on extinguishment of Convertible Note and modification of February 2012 Warrants"* in the consolidated statements of operations for the year ended December 31, 2015 (Predecessor).

On September 9, 2016, and upon emergence from chapter 11 bankruptcy, the Convertible Note and February 2012 Warrants were cancelled. Refer to Note 2, *"Reorganization,"* for further details.

Debt Maturities

Aggregate maturities required on long-term debt at December 31, 2016 (Successor) due in future years are as follows (in thousands, excluding discounts and debt issuance costs):

2017	$ —
2018	—
2019	186,000
2020[(1)]	700,000
2021	—
Thereafter	112,826
Total	$998,826

(1) On February 16, 2017 (Successor), the Company issued $850.0 million aggregate principal amount of new 6.75% senior unsecured notes due 2025. A portion of the net proceeds from the issuance of the new 6.75% senior unsecured notes were used to fund the repurchase of the validly tendered 2020 Second Lien Notes. These transactions are not included in the table above. See Note 17, "Subsequent Events," for more details.

Debt Issuance Costs

The Company capitalizes certain direct costs associated with the issuance of debt and amortizes such costs over the lives of the respective debt. For the period from January 1, 2016 through September 9, 2016, the Predecessor Company expensed $7.9 million of debt issuance costs in conjunction with debt repurchases, decreases in the borrowing base under the Predecessor Credit Agreement, and refinancing of the Predecessor Credit Agreement. At December 31, 2015 (Predecessor), the Company had approximately $40.3 million of debt issuance costs capitalized related to its Predecessor senior secured and unsecured debt. As part of the Company's reorganization, all debt issuance costs related to the Company's Predecessor debt were extinguished. The debt issuance costs for the Company's Predecessor Credit Agreement were presented in *"Debt issuance costs, net"*, and the debt issuance costs for the Company's senior unsecured debt were presented in *"Long-term debt, net"* within total liabilities on the consolidated balance sheet at December 31, 2015 (Predecessor).

8. FAIR VALUE MEASUREMENTS

Pursuant to ASC 820, the Company's determination of fair value incorporates not only the credit standing of the counterparties involved in transactions with the Company resulting in receivables on the Company's consolidated balance sheets, but also the impact of the Company's nonperformance risk on

8. FAIR VALUE MEASUREMENTS (Continued)

its own liabilities. ASC 820 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 (exit price). ASC 820 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy assigns the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Level 2 measurements are inputs that are observable for assets or liabilities, either directly or indirectly, other than quoted prices included within Level 1. The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. The Company classifies fair value balances based on the observability of those inputs.

As required by ASC 820, a financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There were no transfers between fair value hierarchy levels for any period presented. The following tables set forth by level within the fair value hierarchy the Company's financial assets and liabilities that were accounted for at fair value as of December 31, 2016 (Successor) and 2015 (Predecessor) (in thousands):

	Successor			
	December 31, 2016			
	Level 1	Level 2	Level 3	Total
Assets				
Receivables from derivative contracts	$—	$ 5,923	$—	$ 5,923
Liabilities				
Liabilities from derivative contracts	$—	$16,920	$—	$16,920

	Predecessor			
	December 31, 2015			
	Level 1	Level 2	Level 3	Total
Assets				
Receivables from derivative contracts	$—	$365,475	$ —	$365,475
Liabilities				
Liabilities from derivative contracts	$—	$ 105	$185	$ 290

Derivative contracts listed above as Level 2 include collars, swaps and swaptions that are carried at fair value. The Company records the net change in the fair value of these positions in *"Net gain (loss) on derivative contracts"* in the Company's consolidated statements of operations. The Company is able to value the assets and liabilities based on observable market data for similar instruments, which resulted in the Company reporting its derivatives as Level 2. This observable data includes the forward curves for commodity prices based on quoted markets prices and implied volatility factors related to

8. FAIR VALUE MEASUREMENTS (Continued)

changes in the forward curves. See Note 9, *"Derivative and Hedging Activities,"* for additional discussion of derivatives.

Derivative contracts listed above as Level 3 include extendable collars that are carried at fair value. The significant unobservable inputs for these Level 3 contracts include unpublished forward strip prices and market volatilities. The following table sets forth a reconciliation of changes in the fair value of the Company's extendable collar contracts classified as Level 3 in the fair value hierarchy (in thousands):

	Significant Unobservable Inputs (Level 3)	
	Successor	Predecessor
	December 31, 2016	December 31, 2015
Beginning Balance	$(185)	$(1,319)
Net gain (loss) on derivative contracts	185	1,134
Ending Balance	$ —	$ (185)

	Successor	Predecessor	
	Period from September 10, 2016 through December 31, 2016	Period from January 1, 2016 through September 9, 2016	December 31, 2015
Change in unrealized gains (losses) included in earnings related to derivatives still held at December 31, 2016 (Successor), September 9, 2016 (Predecessor) and December 31, 2015 (Predecessor)	$—	$137	$(185)

The Company's derivative contracts are with major financial institutions with investment grade credit ratings which are believed to have minimal credit risk. As such, the Company is exposed to credit risk to the extent of nonperformance by the counterparties in the derivative contracts; however, the Company does not anticipate such nonperformance.

The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of ASC 825, *Financial Instruments*. The estimated fair value amounts have been determined at discrete points in time based on relevant market information. These estimates involve uncertainties and cannot be determined with precision. The estimated fair value of cash, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. The estimated fair value of the Company's Senior Credit Agreement approximates carrying value because the interest rates approximate current market rates. The following table presents the estimated fair values of the Company's fixed interest rate, long-term debt instruments as of December 31, 2016

8. FAIR VALUE MEASUREMENTS (Continued)

(Successor) and 2015 (Predecessor) (excluding discounts, premiums and debt issuance costs) (in thousands):

	Successor		Predecessor	
	December 31, 2016		December 31, 2015	
Debt	Principal Amount	Estimated Fair Value	Principal Amount	Estimated Fair Value
8.625% senior secured second lien notes	700,000	$733,250	$ 700,000	$ 479,500
12.0% senior secured second lien notes	112,826	123,827	112,826	77,286
13.0% senior secured third lien notes(1)	—	—	1,017,970	333,385
9.25% senior notes(1)	—	—	52,694	14,422
8.875% senior notes(1)	—	—	348,944	95,506
9.75% senior notes(1)	—	—	340,035	93,068
8.0% convertible note(1)	—	—	289,669	87,393
	$812,826	$857,077	$2,862,138	$1,180,560

(1) These notes were cancelled on September 9, 2016 upon emergence from chapter 11 bankruptcy.

The fair value of the Company's fixed interest debt instruments was calculated using Level 2 criteria at December 31, 2016 (Successor) and 2015 (Predecessor). The fair value of the Company's senior notes is based on quoted market prices from trades of such debt. The fair value of the Company's convertible note was based on published market prices and risk-free rates.

On September 9, 2016, the Company emerged from chapter 11 bankruptcy and adopted fresh-start accounting, which resulted in the Company becoming a new entity for financial reporting purposes. Upon the adoption of fresh-start accounting, the Company's assets and liabilities were recorded at their fair values as of the fresh-start reporting date, September 9, 2016. See Note 3, *"Fresh-start Accounting,"* for a detailed discussion of the fair value approaches used by the Company.

During the three months ended March 31, 2016 and the year ended December 31, 2014, the Predecessor Company recorded non-cash impairment charges of $28.1 million and $35.6 million, respectively, related to its gas gathering systems. See Note 1, *"Summary of Significant Events and Accounting Policies,"* for a discussion of the valuation approach used and the classification of the estimate within the fair value hierarchy.

As discussed in Note 7, "*Long-term Debt,*" and in Note 13, "*Stockholders' Equity*," on May 6, 2015, the HALRES Note Amendment and the Warrant Amendment became effective. The fair value estimates for the Convertible Note and the February 2012 Warrants include the use of observable inputs such as the Predecessor Company's stock price, expected volatility, and credit spread and the risk-free rate. The use of these observable inputs results in the fair value estimates being classified as Level 2.

The Company follows the provisions of ASC 820, for nonfinancial assets and liabilities measured at fair value on a non-recurring basis. These provisions apply to the Company's initial recognition of asset retirement obligations for which fair value is used. The asset retirement obligation estimates are derived from historical costs and management's expectation of future cost environments; and therefore, the Company has designated these liabilities as Level 3. See Note 10, *"Asset Retirement Obligations,"* for a reconciliation of the beginning and ending balances of the liability for the Company's asset retirement obligations.

9. DERIVATIVE AND HEDGING ACTIVITIES

The Company is exposed to certain risks relating to its ongoing business operations, such as commodity price risk and interest rate risk. Derivative contracts are utilized to hedge the Company's exposure to price fluctuations and reduce the variability in the Company's cash flows associated with anticipated sales of future oil and natural gas production. When derivative contracts are available at terms (or prices) acceptable to the Company, it generally hedges a substantial, but varying, portion of anticipated oil and natural gas production for future periods. Derivatives are carried at fair value on the consolidated balance sheets as assets or liabilities, with the changes in the fair value included in the consolidated statements of operations for the period in which the change occurs. The Company's hedge policies and objectives may change significantly as its operational profile changes and/or commodities prices change. The Company does not enter into derivative contracts for speculative trading purposes.

It is the Company's policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. The Company did not post collateral under any of its derivative contracts as they are secured under the Company's Senior Credit Agreement or are uncollateralized trades.

The Company's crude oil and natural gas derivative positions at any point in time may consist of swaps, swaptions, costless put/call "collars," extendable costless collars and deferred put options. Swaps are designed so that the Company receives or makes payments based on a differential between fixed and variable prices for crude oil and natural gas. Swaptions are swap contracts that may be extended annually at the option of the counterparty on a designated date. A costless collar consists of a sold call, which establishes a maximum price the Company will receive for the volumes under contract and a purchased put that establishes a minimum price. Extendable collars are costless put/call contracts that may be extended annually at the option of the counterparty on a designated date. A sold put option limits the exposure of the counterparty's risk should the price fall below the strike price. Sold put options limit the effectiveness of purchased put options at the low end of the put/call collars to market prices in excess of the strike price of the put option sold. The Company has elected to not designate any of its derivative contracts for hedge accounting. Accordingly, the Company records the net change in the mark-to-market valuation of these derivative contracts, as well as all payments and receipts on settled derivative contracts, in *"Net gain (loss) on derivative contracts"* on the consolidated statements of operations.

At December 31, 2016 (Successor), the Company had 22 open commodity derivative contracts summarized in the following tables: two natural gas collar arrangements and 20 crude oil collar arrangements.

At December 31, 2015 (Predecessor), the Company had 36 open commodity derivative contracts summarized in the following tables: one natural gas collar arrangement, 16 crude oil collar arrangements, 13 crude oil swaps, five crude oil swaptions and one crude oil extendable collar.

All derivative contracts are recorded at fair market value in accordance with ASC 815 and ASC 820 and included in the consolidated balance sheets as assets or liabilities. The following table

9. DERIVATIVE AND HEDGING ACTIVITIES (Continued)

summarizes the location and fair value amounts of all derivative contracts in the consolidated balance sheets as of December 31, 2016 (Successor) and 2015 (Predecessor) (in thousands):

Derivatives not designated as hedging contracts under ASC 815	Balance sheet location	Asset derivative contracts Successor December 31, 2016	Asset derivative contracts Predecessor December 31, 2015	Balance sheet location	Liability derivative contracts Successor December 31, 2016	Liability derivative contracts Predecessor December 31, 2015
Commodity contracts	Current assets—receivables from derivative contracts	$5,923	$348,861	Current liabilities—liabilities from derivative contracts	$(16,434)	$ —
Commodity contracts	Other noncurrent assets—receivables from derivative contracts	—	16,614	Other noncurrent liabilities—liabilities from derivative contracts	(486)	(290)
Total derivatives not designated as hedging contracts under ASC 815		$5,923	$365,475		$(16,920)	$(290)

The following table summarizes the location and amounts of the Company's realized and unrealized gains and losses on derivative contracts in the Company's consolidated statements of operations (in thousands):

Derivatives not designated as hedging contracts under ASC 815	Location of gain or (loss) recognized in income on derivative contracts	Successor: Period from September 10, 2016 through December 31, 2016	Predecessor: Period from January 1, 2016 through September 9, 2016	Predecessor: Years Ended December 31, 2015	Predecessor: Years Ended December 31, 2014
Commodity contracts:					
Unrealized gain (loss) on commodity contracts	Other income (expenses)—net gain (loss) on derivative contracts	$(112,449)	$(263,732)	$(129,282)	$506,526
Realized gain (loss) on commodity contracts	Other income (expenses)—net gain (loss) on derivative contracts	84,709	245,734	439,546	12,430
Total net gain (loss) on derivative contracts		$ (27,740)	$ (17,998)	$ 310,264	$518,956

At December 31, 2016 (Successor) and 2015 (Predecessor), the Company had the following open crude oil and natural gas derivative contracts:

			Successor				
			December 31, 2016				
				Floors		Ceilings	
Period	Instrument	Commodity	Volume in Mmbtu's/ Bbl's	Price / Price Range	Weighted Average Price	Price / Price Range	Weighted Average Price
January 2017 - December 2017	Collars	Natural Gas	3,650,000	$3.15 - $3.26	$ 3.20	$3.50 - $3.76	$ 3.63
January 2017 - December 2017	Collars	Crude Oil	6,843,750	47.00 - 60.00	51.39	52.00 - 76.84	58.75
January 2018 - December 2018[(1)]	Collars	Crude Oil	730,000	53.00	53.00	58.00	58.00

9. DERIVATIVE AND HEDGING ACTIVITIES (Continued)

			Predecessor				
			December 31, 2015				
				Floors		Ceilings	
Period	Instrument	Commodity	Volume in Mmbtu's/ Bbl's	Price / Price Range	Weighted Average Price	Price / Price Range	Weighted Average Price
January 2016 - June 2016	Collars	Crude Oil	182,000	$90.00	$90.00	$96.85	$96.85
January 2016 - December 2016	Collars	Natural Gas	732,000	4.00	4.00	4.22	4.22
January 2016 - December 2016(2)	Collars	Crude Oil	4,392,000	60.00 - 90.00	71.91	64.00 - 95.10	77.71
January 2016 - December 2016(3)	Swaps	Crude Oil	4,758,000	62.00 - 91.73	85.43		
January 2017 - December 2017	Collars	Crude Oil	1,368,750	50.00 - 60.00	57.33	70.00 - 76.84	74.16

(1) *Subsequent to December 31, 2016, the Company entered into crude oil collars at floors of $50.00 per Bbl and ceilings of $60.00 per Bbl for a total of 730,000 Bbls for the year ended December 31, 2018, which are not included in the table above.*

(2) *Includes an outstanding crude oil collar which may be extended by the counterparty at a floor of $60.00 per Bbl and a ceiling of $75.00 per Bbl for a total of 365,000 Bbls for the year ended December 31, 2017.*

(3) *Includes an outstanding crude oil swap which may be extended by the counterparty at a price of $88.25 per Bbl for a total of 730,000 Bbls for the year ended December 31, 2017. Also includes certain outstanding crude oil swaps which may be extended by the counterparty at a price of $88.00 per Bbl totaling 912,500 Bbls for the year ended December 31, 2017. Includes an outstanding crude oil swap which may be extended by the counterparty at a price of $88.87 per Bbl totaling 547,500 Bbls for the year ended December 31, 2017.*

The Company presents the fair value of its derivative contracts at the gross amounts in the consolidated balance sheets. The following table shows the potential effects of master netting arrangements on the fair value of the Company's derivative contracts at December 31, 2016 (Successor) and 2015 (Predecessor) (in thousands):

	Derivative Assets		Derivative Liabilities	
	Successor	Predecessor	Successor	Predecessor
Offsetting of Derivative Assets and Liabilities	December 31, 2016	December 31, 2015	December 31, 2016	December 31, 2015
Gross amounts presented in the consolidated balance sheet	$ 5,923	$365,475	$(16,920)	$(290)
Amounts not offset in the consolidated balance sheet	(5,283)	(53)	5,075	52
Net amount	$ 640	$365,422	$(11,845)	$(238)

The Company enters into an International Swap Dealers Association Master Agreement (ISDA) with each counterparty prior to a derivative contract with such counterparty. The ISDA is a standard contract that governs all derivative contracts entered into between the Company and the respective counterparty. The ISDA allows for offsetting of amounts payable or receivable between the Company and the counterparty, at the election of both parties, for transactions that occur on the same date and in the same currency.

10. ASSET RETIREMENT OBLIGATIONS

The Company records an asset retirement obligation (ARO) when it can reasonably estimate the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon costs.

10. ASSET RETIREMENT OBLIGATIONS (Continued)

For gas gathering systems and equipment, the Company records an ARO when the system is placed in service and it can reasonably estimate the fair value of an obligation to perform site reclamation and other necessary work when it is required. The Company records the ARO liability on the consolidated balance sheets and capitalizes a portion of the cost in *"Oil and natural gas properties"* or *"Other operating property and equipment"* during the period in which the obligation is incurred. The Company records the accretion of its ARO liabilities in *"Depletion, depreciation and accretion"* expense in the consolidated statements of operations. The additional capitalized costs are depreciated on a unit-of-production basis or straight-line basis.

The Company recorded the following activity related to its ARO liability (in thousands, inclusive of the current portion) (in thousands):

Liability for asset retirement obligation as of December 31, 2014 (Predecessor)	$ 38,477
Liabilities settled and divested	(324)
Additions	3,209
Accretion expense	1,797
Revisions in estimated cash flows	3,857
Liability for asset retirement obligations as of December 31, 2015 (Predecessor)	$ 47,016
Liabilities settled and divested	(180)
Additions	1,044
Acquisitions	75
Accretion expense	1,414
Liability for asset retirement obligations as of September 9, 2016 (Predecessor)	$ 49,369
Fair value fresh-start adjustment	$(16,883)
Liability for asset retirement obligations as of September 9, 2016 (Successor)	$ 32,486
Liabilities settled and divested[1]	(1,211)
Additions	513
Accretion expense	587
Liability for asset retirement obligations as of December 31, 2016 (Successor)	$ 32,375

(1) See Note 5, "Divestitures," for additional information on the Company's divestiture activities.

11. COMMITMENTS AND CONTINGENCIES

Commitments

The Company leases corporate office space in Houston, Texas and Denver, Colorado as well as a number of other field office locations. In addition, the Company has lease commitments for certain equipment under long-term operating lease agreements. The office and equipment operating lease agreements expire on various dates through 2024. Rent expense was approximately $1.4 million for the period of September 10, 2016 through December 31, 2016 (Successor) and $5.9 million for the period of January 1, 2016 through September 9, 2016 (Predecessor). Rent expense was approximately $8.6 million and $8.1 million for the years ended December 31, 2015 and 2014 (Predecessor), respectively. In connection with the chapter 11 bankruptcy, the Company modified and rejected certain office lease arrangements and paid approximately $3.4 million for these modifications and rejections subsequent to the emergence from chapter 11 bankruptcy. Approximate future minimum lease payments for subsequent annual periods for all non-cancelable operating leases as of December 31, 2016 (Successor) are as follows (in thousands):

2017	$ 3,493
2018	3,540
2019	2,997
2020	1,811
2021	1,497
Thereafter	2,180
Total	$15,518

As of December 31, 2016 (Successor), the Company has the following active drilling rig commitments (in thousands):

2017	$17,574
2018	7,444
2019	—
2020	—
2021	—
Thereafter	—
Total	$25,018

As of December 31, 2016 (Successor), termination of the Company's active drilling rig commitments would require early termination penalties of $12.5 million, which would be in lieu of paying the remaining active drilling rig commitments of $25.0 million.

11. COMMITMENTS AND CONTINGENCIES (Continued)

In past years, with the sustained decline in crude oil prices, the Company stacked certain drilling rigs and amended other previous drilling rig contracts. In the future, the Company expects to incur stacking charges/early termination fees on certain drilling rig commitments as follows (in thousands):

2017	$ 6,820
2018	1,260
2019	—
2020	3,000
2021	—
Thereafter	—
Total	$11,080

The Company has entered into an agreement with a private operator for the right to purchase up to 15,040 net acres located in Ward and Winkler Counties, Texas (the Ward County Assets) prospective for the Wolfcamp and Bone Spring formations. The Ward County Assets are divided into two tracts: the Southern Tract, comprising 6,720 net acres, and the Northern Tract, comprising 8,320 net acres, with separate options for each tract. Pursuant to the terms of the agreement, the Company paid $5.0 million and is drilling a commitment well on the Southern Tract. The Company has until June 15, 2017 to exercise the option on either the Southern Tract acreage or on all 15,040 net acres, in each case for $11,000 per acre. If the Company initially elects only to exercise its option on the Southern Tract, the Company would need to pay $5.0 million on or before June 15, 2017 and drill a commitment well on the Northern Tract by September 1, 2017 to earn an option to acquire the Northern Tract acreage for $11,000 per acre by December 31, 2017. This option purchase not included in the tables above.

The Company has entered into various long-term gathering, transportation and sales contracts in its Bakken/Three Forks formations in North Dakota which are not included in the tables above. As of December 31, 2016 (Successor), the Company had in place eight long-term crude oil contracts and five long-term natural gas contracts in this area and the sales prices under these contracts are based on posted market rates. Under the terms of these contracts, the Company has committed a substantial portion of its Bakken/Three Forks production for periods ranging from one to ten years from the date of first production. The Company believes that there are sufficient available reserves and supplies in the Bakken/Three Forks formations to meet its commitments, as the proved reserves from this area represent approximately 76% of its total proved reserves. Historically, the Company has been able to meet its delivery commitments.

Contingencies

From time to time, the Company may be a plaintiff or defendant in a pending or threatened legal proceeding arising in the normal course of its business. While the outcome and impact of currently pending legal proceedings cannot be determined, the Company's management and legal counsel believe that the resolution of these proceedings through settlement or adverse judgment will not have a material effect on the Company's consolidated operating results, financial position or cash flows.

12. MEZZANINE EQUITY

On June 16, 2014 (Predecessor), funds and accounts managed by affiliates of Apollo contributed $150 million in cash to HK TMS, a Delaware limited liability company, which was then wholly owned by the Company and held all of the Company's acreage in the TMS formation, located in Mississippi and Louisiana, in exchange for the issuance by HK TMS of 150,000 preferred shares. At the closing, the Predecessor Company also contributed $50 million in cash to HK TMS. Holders of the HK TMS preferred shares were to receive quarterly cash dividends of 8% cumulative perpetual per annum, subject to HK TMS' option to pay such dividends "in-kind" through the issuance of additional preferred shares. The preferred shares were expected to be automatically redeemed and cancelled when the holders receive cash dividends and distributions on the preferred shares equating to the greater of a 12% annual rate of return plus principal and 1.25 times their investment plus applicable fees (the Redemption Price), subject to adjustment under certain circumstances. On September 30, 2016, certain wholly-owned subsidiaries of the Successor Company executed an Assignment and Assumption Agreement with an affiliate of Apollo pursuant to which 100% of the Membership Interests in HK TMS were assigned to Apollo. In exchange for the assignment, Apollo assumed all obligations relating to such Membership Interests. See Note 5, *"Divestitures,"* for further information regarding the HK TMS Divestiture.

On June 1, 2015 (Predecessor), HK TMS and Apollo entered into an amendment to the original agreement (the HK TMS Amendment) which, among other things, i) committed HK TMS to drill a minimum of 6.5 net wells in each of the five consecutive twelve month periods beginning December 31, 2015 and ii) allowed for the redemption of preferred shares at the Redemption Price between March 1, 2016 and June 30, 2016 at the election of Apollo to the extent there was available cash above the minimum cash balance, which is discussed further below. For any commitment period in which HK TMS did not meet its drilling obligation, HK TMS would have been required to use available cash, above the minimum cash balance, to redeem preferred shares at the Redemption Price.

The preferred shares were classified as "*Redeemable noncontrolling interest*" and included in *"Mezzanine equity"* between total liabilities and stockholders' equity on the consolidated balance sheets pursuant to ASC 480-10-S99-3A. The preferred shares were considered probable of becoming redeemable and therefore were accreted up to the estimated required redemption value. The accretion was presented as a deemed dividend and recorded in "*Redeemable noncontrolling interest*" on the consolidated balance sheets and within "*Preferred dividends and accretion on redeemable noncontrolling interest*" on the consolidated statements of operations. In accordance with ASC 480-10-S99-3A, an adjustment to the carrying amount presented in mezzanine equity was recognized as charges against retained earnings and reduced income available to common shareholders in the calculation of earnings per share.

HK TMS was required to maintain a minimum cash balance equal to two quarterly dividend payments, of approximately $3.5 million each, plus $10.0 million, which was presented on the consolidated balance sheets in "*Restricted cash*" at December 31, 2015 (Predecessor).

In March 2015 (Predecessor), Apollo delivered a withdrawal notice to HK TMS indicating their election not to acquire additional preferred shares, referred to as the Tranche Rights, in HK TMS (the Withdrawal Notice). Upon issuance of the Withdrawal Notice, HK TMS incurred a fee escalating from $2.50 per share to $20.00 per share for the next eight full fiscal quarters for any preferred shares then outstanding, which began in the quarter ended June 30, 2015 (the Withdrawal Exit Fee). The Withdrawal Exit Fee would have been payable upon redemption of the preferred shares and was

12. MEZZANINE EQUITY (Continued)

recorded at fair value within "*Other noncurrent liabilities*" on the consolidated balance sheets at December 31, 2015 (Predecessor).

For purposes of estimating the fair values of the original and amended transaction components, an income approach was used that estimated fair value based on the anticipated cash flows associated with the Company's proved reserves, discounted using a weighted average cost of capital rate. The estimation of the fair value of these components includes the use of unobservable inputs, such as estimates of proved reserves, the weighted average scost of capital (discount rate), estimated future revenues, and estimated future capital and operating costs. The use of these unobservable inputs results in the fair value estimates being classified as Level 3. Although the Company believes the assumptions and estimates used in the fair value calculation of the original and amended transaction components are reasonable and appropriate, different assumptions and estimates could materially impact the analysis and resulting conclusions. The assumptions used in estimating the fair value of the original and amended transaction components are inherently uncertain and require management judgment.

The following table sets forth a reconciliation of the changes in fair value of the Tranche Rights and embedded derivative classified as Level 3 in the fair value hierarchy (in thousands):

	Tranche rights	Embedded derivative
Balances at December 31, 2014 (Predecessor)	$(2,634)	$ 5,963
Change in fair value	2,634	137
Balances at December 31, 2015 (Predecessor)	—	6,100
Change in fair value	—	(5,734)
Balance at September 9, 2016 (Predecessor)	$ —	$ 366
Fair value fresh-start adjustment	—	(366)
Balance at September 9, 2016 (Successor) and at December 31, 2016 (Successor)	$ —	$ —

12. MEZZANINE EQUITY (Continued)

The Company recorded the following activity related to the preferred shares in *"Mezzanine equity"* on the consolidated balance sheets for the years ended December 31, 2016 (Successor) and 2015 (Predecessor) (in thousands, except share amounts):

	Redeemable noncontrolling interest	
	Shares	Amount
Balances at December 31, 2014 (Predecessor)	153,025	$ 117,166
Dividends paid in-kind	12,614	12,614
Accretion of redeemable noncontrolling interest	—	53,561
Deemed dividend for change in fair value due to the HK TMS Amendment	—	645
Balances at December 31, 2015 (Predecessor)	165,639	$ 183,986
Dividends paid in-kind	9,329	9,329
Accretion of redeemable noncontrolling interest	—	26,576
Balances at September 9, 2016 (Predecessor)	174,968	$ 219,891
Fair value fresh-start adjustment	—	$(178,821)
Balances at September 9, 2016 (Successor)	174,968	$ 41,070
Dividends paid in-kind	791	791
HK TMS Divestiture[(1)]	(175,759)	(41,861)
Balance at December 31, 2016 (Successor)	—	$ —

(1) See Note 5, "Divestitures," for additional information on the HK TMS Divestiture.

For the period of September 10, 2016 through September 30, 2016 (Successor) and January 1, 2016 through September 9, 2016 (Predecessor), HK TMS issued 791 and 9,329 additional preferred shares to Apollo for dividends paid-in-kind, respectively. For the year ended December 31, 2015 (Predecessor), HK TMS issued 12,614 additional preferred shares to Apollo for dividends paid in-kind. For the year ended December 31, 2014 (Predecessor), HK TMS paid approximately $3.5 million in cash dividends and issued 3,025 additional preferred shares for dividends paid-in-kind. These dividends were presented within "*Preferred dividends and accretion on redeemable noncontrolling interest*" on the consolidated statements of operations. Upon the election of in-kind dividends, HK TMS was required to pay a fee of $5.00 per preferred share then outstanding (PIK exit fee). Such fees would have been due upon redemption of the preferred shares. For the years ended December 31 2015 and 2014 (Predecessor), HK TMS incurred PIK exit fees totaling $3.1 million and $0.8 million, respectively, which were recorded at fair value within "*Other noncurrent liabilities*" on the consolidated balance sheets.

HK TMS was not included in the chapter 11 bankruptcy filings or the Restructuring Support Agreement discussed in Note 2, *"Reorganization."* On September 30, 2016, Apollo acquired one hundred percent of the common shares of HK TMS and assumed all obligations relating to the Membership Interests. For additional information regarding the divestiture see Note 5, *"Divestitures."*

13. STOCKHOLDERS' EQUITY

Common Stock

On September 9, 2016, upon emergence from chapter 11 bankruptcy, all existing shares of Predecessor common stock were cancelled and the Successor Company issued approximately 90.0 million shares of common stock in total to the Predecessor Company's existing common stockholders, Third Lien Noteholders, Unsecured Noteholders, and the Convertible Noteholder. Refer to Note 2, "*Reorganization,*" for further details.

On September 9, 2016, upon emergence from chapter 11 bankruptcy, the Successor Company filed an amended and restated certificate of incorporation with the Delaware Secretary of State to provide for (i) the total number of shares of all classes of capital stock that the Successor Company has the authority to issue is 1,001,000,000 of which 1,000,000,000 shares are common stock, par value $0.0001 per share and 1,000,000 shares are preferred stock, par value $0.0001 per share, (ii) a classified board structure, (iii) the right of removal of directors with or without cause by stockholders, and (iv) a restriction on the Successor Company from issuing any non-voting equity securities in violation of Section 1123(a)(6) of chapter 11 of title 11 of the United States Code.

During the second quarter of 2015, the Predecessor Company entered into several exchange agreements with holders of the Predecessor Company's senior unsecured notes in which they agreed to exchange an aggregate $258.0 million principal amount of their senior notes for approximately 29.0 million shares of the Predecessor Company's common stock. The Predecessor Company recorded the issuance of common shares at fair value on the various dates the debt for equity exchanges occurred.

On March 18, 2015, the Predecessor Company entered into an Equity Distribution Agreement (the Equity Distribution Agreement) with BMO Capital Markets Corp., Jefferies LLC and MLV & Co. LLC (collectively, the Managers). Pursuant to the terms of the Equity Distribution Agreement, the Predecessor Company sold, by means of ordinary brokers' transactions through the facilities of the NYSE at market prices, a total of approximately 1.9 million shares of the Predecessor Company's common stock for net proceeds of approximately $15.0 million, after deducting offering expenses. The shares sold were registered under the Securities Act pursuant to a Registration Statement on Form S-3 (No. 333-188640), which was filed with the SEC and became effective March 13, 2015. The Predecessor Company used the net proceeds from the offering to repay a portion of the then outstanding borrowings under its Predecessor Credit Agreement and for general corporate purposes.

On May 22, 2014, upon stockholder approval, the Predecessor Company filed a Certificate of Amendment of the Amended and Restated Certificate of Incorporation with the Delaware Secretary of State to increase its authorized common stock by approximately 670.0 million shares for a total of 1.34 billion authorized shares of common stock.

5.75% Series A Convertible Perpetual Preferred Stock

On June 18, 2013, the Predecessor Company completed its offering of 345,000 shares of its Predecessor 5.75% Series A Convertible Perpetual Preferred Stock (the Predecessor Series A Preferred Stock) at a public offering price of $1,000 per share (the Liquidation Preference). The Predecessor Company filed a Certificate of Designations, Preferences, Rights and Limitations of 5.75% Series A Convertible Preferred Stock on June 17, 2013 (the Series A Designation). The net proceeds to the Predecessor Company from the offering of the Predecessor Series A Preferred Stock were

13. STOCKHOLDERS' EQUITY (Continued)

approximately $335.2 million, after deducting the underwriting discount and offering expenses. The Predecessor Company used the net proceeds from the offering to repay a portion of the then outstanding borrowings under its Predecessor Credit Agreement.

Holders of the Predecessor Series A Preferred Stock were entitled to receive, when, as and if declared by the Predecessor Company's board of directors, cumulative dividends at the rate of 5.75% per annum (the dividend rate) on the Liquidation Preference per share of the Predecessor Series A Preferred Stock, payable quarterly in arrears on each dividend payment date. Dividends were paid in cash or, where freely transferable by any non-affiliate recipient thereof, in common stock of the Predecessor Company or a combination thereof, and were payable on March 1, June 1, September 1 and December 1 of each year and commenced on September 1, 2013. In January 2016, the Predecessor Company announced that quarterly dividends on the Predecessor Series A Preferred Stock were suspended due to the weakened market conditions as a result of low commodity prices. During the years ended December 31, 2015 and 2014 (Predecessor), the Company incurred cumulative, declared dividends of $18.0 million by paying $8.2 million in cash and issuing approximately 1.4 million shares of common stock and $19.8 million by paying $5.0 million in cash and issuing approximately 0.7 million shares of common stock, respectively, reflected as cash and non-cash dividends. As of September 9, 2016 (Predecessor) and December 31, 2015 (Predecessor), cumulative, undeclared dividends on the Predecessor Series A Preferred Stock amounted to approximately $9.9 million and $1.2 million, respectively.

On September 9, 2016, upon emergence from chapter 11 bankruptcy, all existing shares of Predecessor Series A Preferred Stock were cancelled and the Preferred Holders received their pro rata share of $11.1 million in cash, in full and final satisfaction of their interests. Refer to Note 2, "*Reorganization,*" for further details.

Warrants

On September 9, 2016, upon the emergence from chapter 11 bankruptcy, all existing February 2012 warrants were cancelled and the Successor Company issued 3.8 million new warrants to the Unsecured Noteholders and 0.9 million new warrants to the Convertible Noteholder. The warrants in aggregate can be exercised to purchase 4.7 million shares of the Successor Company's common stock at an exercise price of $14.04 per share. The Company allocated approximately $16.7 million of the Enterprise Value to the warrants which is reflected in "*Successor Additional paid-in capital*" on the consolidated balance sheet at December 31, 2016 (Successor). The holders are entitled to exercise the warrants in whole or in part at any time prior to expiration on September 9, 2020. See Note 2, "*Reorganization,*" for further details.

In February 2012, in conjunction with the issuance of the Convertible Note, the Predecessor Company issued the February 2012 Warrants to purchase 7.3 million shares of the Predecessor Company's common stock at an exercise price of $22.50 per share of common stock. The Predecessor Company allocated $43.6 million to the February 2012 Warrants which is reflected in *"Predecessor Additional paid-in capital"* on the consolidated balance sheet at December 31, 2015 (Predecessor), net of $0.6 million in issuance costs. The February 2012 Warrants entitled the holders to exercise the warrants in whole or in part at any time prior to the expiration date of February 8, 2017.

On March 9, 2015, in conjunction with the HALRES Note Amendment, the Predecessor Company entered into an amendment to the February 2012 Warrants, the Warrant Amendment, which extended

13. STOCKHOLDERS' EQUITY (Continued)

the term of the February 2012 Warrants from February 8, 2017 to February 8, 2020 and adjusted the exercise price from $22.50 to $12.20 per share. The Warrant Amendment was approved by the Predecessor Company's stockholders on May 6, 2015, in accordance with the rules of the NYSE. The Predecessor Company expensed approximately $14.1 million for the change in the fair value of the February 2012 Warrants immediately before and after the Warrant Amendment in *"Gain (loss) on extinguishment of Convertible Note and modification of February 2012 Warrants"* in the consolidated statements of operations for the year ended December 31, 2015 (Predecessor). See Note 6, "*Long-term debt*," for further discussion of the HALRES Note Amendment and the Warrant Amendment.

Incentive Plans

On May 8, 2006, the Company's stockholders first approved its 2006 Long-Term Incentive Plan (Predecessor Incentive Plan). On May 6, 2015, shareholders last approved an increase in authorized shares under the Predecessor Incentive Plan from 8.3 million to 16.3 million. As of December 31, 2015, a maximum of 6.3 million shares of Predecessor common stock remained reserved for issuance under the Predecessor Incentive Plan.

Immediately prior to emergence from chapter 11 bankruptcy, the Predecessor Incentive Plan was cancelled and all share-based compensation awards granted thereunder were either vested or cancelled and Predecessor Company's Board adopted the 2016 Long-Term Incentive Plan (the 2016 Incentive Plan). An aggregate of 10.0 million shares of the Successor Company's common stock were available for grant pursuant to awards under the 2016 Incentive Plan in the form of nonqualified stock options, incentive stock options, restricted stock awards, restricted stock units, stock appreciation rights, performance units, performance bonuses, stock awards and other incentive awards. As of December 31, 2016 (Successor), a maximum of 1.7 million shares of the Successor Company's common stock remained reserved for issuance under the 2016 Incentive Plan.

The Company accounts for share-based payment accruals under authoritative guidance on stock compensation. The guidance requires all share-based payments to employees and directors, including grants of stock options, and restricted stock, to be recognized in the financial statements based on their fair values. For awards granted under the 2016 Incentive Plan subsequent to emerging from chapter 11 bankruptcy and in conjunction with the early adoption of ASU 2016-09, the Successor Company has elected to not apply a forfeiture estimate and will recognize a credit in compensation expense to the extent awards are forfeited.

For the period from September 10, 2016 through December 31, 2016 (Successor) and the period from January 1, 2016 through September 9, 2016 (Predecessor) the Company recognized $21.5 million and $4.9 million, respectively, of share-based compensation expense. For the years ended December 31, 2015 and 2014 (Predecessor), the Company recognized $14.5 million and $18.7 million, respectively, of share-based compensation expense. Share-based compensation expense is recorded as a component of "*General and administrative*" on the consolidated statements of operations.

Performance Share Units

As of December 31, 2015 (Predecessor), the Company had outstanding performance share units (PSU) under the Predecessor Incentive Plan covering 0.3 million shares of common stock granted to senior management in 2014. The PSU provided that the number of shares of Predecessor common stock received upon vesting would vary if the market price of the Predecessor Company's common

13. STOCKHOLDERS' EQUITY (Continued)

stock exceeded certain pre-established target thresholds as measured by the average of the adjusted closing price of a share of the Predecessor Company's common stock during the sixty trading days preceding the third anniversary of issuance, or the measurement date. The Company had reserved for issuance under the Predecessor Incentive Plan the maximum number of shares that participants might have the right to receive upon vesting of the PSU, or 0.6 million shares of common stock.

No PSUs were granted during the period from January 1, 2016 through September 9, 2016 (Predecessor) or in 2015 (Predecessor). The weighted average grant date fair value of PSUs granted in 2014 (Predecessor) was $4.9 million. At December 31, 2015 (Predecessor) the unrecognized compensation expense related to non-vested PSUs totaled $1.9 million. The weighted average remaining vesting period as of December 31, 2015 (Predecessor) was 1.2 years.

Immediately prior to emergence from chapter 11 bankruptcy, all outstanding PSUs under the Predecessor Incentive Plan were cancelled. Refer to Note 2, *"Reorganization,"* for further details.

The following table sets forth the PSU transactions for the period from January 1, 2016 through September 9, 2016 (Predecessor) and the years ended December 31, 2015 and 2014 (Predecessor):

	Number of Shares	Weighted Average Grant Date Fair Value Per Share	Aggregate Intrinsic Value(1) (In thousands)
Unvested outstanding shares at December 31, 2013 (Predecessor)	—	$ —	$—
Granted	320,830	15.40	
Vested	—	—	
Forfeited	—	—	
Unvested outstanding shares at December 31, 2014 (Predecessor)	320,830	$15.40	$—
Granted	—	—	
Vested	—	—	
Forfeited	—	—	
Unvested outstanding shares at December 31, 2015 (Predecessor)	320,830	$15.40	$—
Granted	—	—	
Vested	—	—	
Forfeited	—	—	
Cancelled(2)	(320,830)	15.40	
Unvested outstanding shares at September 9, 2016 (Predecessor)	—	$ —	$—

(1) *The intrinsic value of PSUs was calculated as the average closing market price on December 31, 2015 and 2014 (Predecessor) of the underlying stock multiplied by the number of PSUs that would be convertible. There were no vested PSUs as of December 31, 2015 and 2014 (Predecessor).*

(2) *Immediately prior to emergence from chapter 11 bankruptcy, all outstanding PSUs under the Predecessor Incentive Plan were cancelled.*

13. STOCKHOLDERS' EQUITY (Continued)

The assumptions used in calculating the Monte Carlo simulation model fair value of the Company's PSUs for the year ended December 31, 2014 (Predecessor) are disclosed in the following table:

	Predecessor
	Year Ended December 31, 2014
Weighted average value per PSUs granted during the period	$15.40
Assumptions:	
Stock price volatility[(1)]	48.00%
Risk free rate of return	0.68%
Expected term	3 years

(1) Due to the Company's limited historical data, expected volatility was estimated using volatilities of similar entities whose share or option prices and assumptions were publicly available.

Stock Options

From time to time, the Company grants stock options under its incentive plans covering shares of common stock to employees of the Company. Stock options, when exercised, are settled through the payment of the exercise price in exchange for new shares of stock underlying the option. These awards typically vest over a three year period at a rate of one-third on the annual anniversary date of the grant and expire ten years from the grant date.

No options were granted from the period January 1, 2016 through September 9, 2016 (Predecessor). The weighted average grant date fair value of options granted in 2015 and 2014 (Predecessor) was $4.9 million, and $13.2 million, respectively. At December 31, 2015 (Predecessor), the unrecognized compensation expense related to non-vested stock options totaled $6.2 million. The weighted average remaining vesting period as of December 31, 2015 (Predecessor) was 1.3 years.

Immediately prior to emergence from chapter 11 bankruptcy, all outstanding stock options under the Predecessor Incentive Plan were cancelled. Refer to Note 2, *"Reorganization,"* for further details.

The weighted average grant date fair value of options granted during the period from September 10, 2016 through December 31, 2016 (Successor) was $32.3 million. At December 31, 2016 (Successor), the Company had $26.5 million of unrecognized compensation expense related to non-vested stock options to be recognized over a weighted-average period of 1.7 years.

13. STOCKHOLDERS' EQUITY (Continued)

The following table sets forth the stock option transactions for the period from September 10, 2016 through December 31, 2016 (Successor), January 1, 2016 through September 9, 2016 (Predecessor) and the years ended December 31, 2015 and 2014 (Predecessor):

	Number	Weighted Average Exercise Price Per Share	Aggregate Intrinsic Value(1) (In thousands)	Weighted Average Remaining Contractual Life (Years)
Outstanding at December 31, 2013 (Predecessor)	2,083,237	$35.75	$ —	9.0
Granted	1,936,764	14.70		
Exercised	—	—		
Forfeited	(235,269)	31.05		
Outstanding at December 31, 2014 (Predecessor)	3,784,732	$25.25	$724	8.7
Granted	1,922,467	5.36		
Exercised	—	—		
Forfeited	(847,066)	22.97		
Outstanding at December 31, 2015 (Predecessor)	4,860,133	$17.80	$ —	8.4
Granted	—	—		
Exercised	—	—		
Forfeited	(695,302)	21.17		
Cancelled(2)	(4,164,831)	17.23		
Outstanding at September 9, 2016 (Predecessor)	—	$ —	$ —	—
Outstanding at September 9, 2016 (Successor)	—	$ —	$ —	—
Granted	5,319,400	9.22		
Exercised	—	—		
Forfeited	—	—		
Outstanding at December 31, 2016 (Successor)	5,319,400	$ 9.22	$631	9.7

(1) The intrinsic value of stock options was calculated as the amount by which the closing market price on December 31, 2016 (Successor) and December 31, 2015 and 2014 (Predecessor) of the underlying stock exceeded the exercise price of the option. No stock options were exercised during the period from September 10, 2016 through December 31, 2016 (Successor), the period from January 1, 2016 through September 9, 2016 (Predecessor), or the years ended December 31, 2015 and 2014 (Predecessor).

(2) Immediately prior to emergence from chapter 11 bankruptcy, all outstanding options under the Predecessor Incentive Plan were cancelled.

13. STOCKHOLDERS' EQUITY (Continued)

Options outstanding at December 31, 2016 (Successor) consisted of the following:

	Outstanding			Exercisable[(1)]			
Range of Grant Prices Per Share	Number	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Live (Years)	Number	Weighted Average Exercise Price per Share	Aggregate Intrinsic Value	Weighted Average Remaining Contractual Live (Years)
$8.93	319,400	$8.93	10.0	—	$—	$—	—
$9.24	5,000,000	9.24	9.7	—	—	—	—

(1) *At December 31, 2016 (Successor), none of the Company's options were exercisable due to service performance conditions.*

The assumptions used in calculating the Black-Scholes-Merton valuation model fair value of the Company's stock options for the period from September 10, 2016 through December 31, 2016 (Successor) and the years ended December 31, 2015 and 2014 (Predecessor) are set forth in the following table:

	Successor	Predecessor	
	Period from September 10, 2016 through December 31, 2016	Years Ended December 31, 2015	Years Ended December 31, 2014
Weighted average value per option granted during the period	$6.07	$2.56	$6.80
Assumptions:			
Stock price volatility[(1)]	56.29%	56.45%	51.48%
Risk free rate of return	1.34%	1.66%	1.56%
Expected term	6 years	5 years	5 years

(1) *Due to the Company's limited historical data, expected volatility was estimated using volatilities of similar entities whose share or option prices and assumptions were publicly available.*

Restricted Stock

From time to time, the Company grants shares of restricted stock to employees and non-employee directors of the Company. Employee shares typically vest over a three year period at a rate of one-third on the annual anniversary date of the grant, and the non-employee directors' shares vest six months from the date of grant. For certain shares granted under the 2016 Incentive Plan, subsequent to emergence from chapter 11 bankruptcy, half vested immediately on the date of the grants and the remaining half will vest on the first anniversary of the date of grants.

No restricted shares were granted from the period January 1, 2016 through September 9, 2016 (Predecessor). The weighted average grant date fair value of the shares granted in 2015 and 2014 (Predecessor) was $8.5 million and $23.7 million, respectively. At December 31, 2015 (Predecessor), the unrecognized compensation expense related to non-vested restricted stock totaled $11.1 million. The weighted average remaining vesting period as of December 31, 2015 (Predecessor) was 1.5 years.

Immediately prior to emergence from chapter 11 bankruptcy, all outstanding unvested restricted stock awards granted under the Predecessor Incentive Plan were vested. Refer to Note 2, *"Reorganization,"* for further details.

13. STOCKHOLDERS' EQUITY (Continued)

The weighted average grant date fair value of shares granted during the period from September 10, 2016 through December 31, 2016 (Successor) was $27.3 million. At December 31, 2016 (Successor), the Company had $11.5 million of unrecognized compensation expense related to non-vested restricted stock awards to be recognized over a weighted-average period of 0.9 years.

The following table sets forth the restricted stock transactions for the period from September 10, 2016 through December 31, 2016 (Successor), January 1, 2016 through September 9, 2016 (Predecessor) and the years ended December 31, 2015 and 2014 (Predecessor):

	Number of Shares	Weighted Average Grant Date Fair Value Per Share	Aggregate Intrinsic Value(1) (In thousands)
Unvested outstanding shares at December 31, 2013 (Predecessor)	528,676	$35.80	$10,204
Granted	1,877,608	12.60	
Vested	(246,232)	34.05	
Forfeited	(91,141)	23.05	
Unvested outstanding shares at December 31, 2014 (Predecessor)	2,068,911	$15.55	$18,413
Granted	2,047,785	4.15	
Vested	(858,708)	16.24	
Forfeited	(387,583)	12.86	
Unvested outstanding shares at December 31, 2015 (Predecessor)	2,870,405	$ 7.55	$ 3,617
Granted	—	—	
Vested	(436,256)	18.50	
Accelerated vesting(2)	(1,917,072)	5.39	
Forfeited	(517,077)	6.31	
Unvested outstanding shares at September 9, 2016 (Predecessor)	—	$ —	$ —
Unvested shares outstanding at September 9, 2016 (Successor)	—	$ —	$ —
Granted	2,991,202	9.14	
Vested	(1,253,125)	9.24	
Forfeited	—	—	
Unvested shares outstanding at December 31, 2016 (Successor)	1,738,077	$ 9.06	$16,234

(1) The intrinsic value of restricted stock was calculated as the closing market price on December 31, 2016 (Successor) and December 31, 2015 and 2014 (Predecessor) of the underlying stock multiplied by the number of restricted shares. The total fair value of shares vested was $11.6 million for the period from September 10, 2016 to December 31, 2016 (Successor). The total fair value of shares vested was $0.9 million, $5.2 million, and $5.1 million for the period from January 1, 2016 through September 9, 2016 (Predecessor) and the years ended December 31, 2015 and 2014 (Predecessor).

(2) Immediately prior to emergence from chapter 11 bankruptcy, all outstanding unvested restricted stock under the Predecessor Incentive Plan were vested.

14. INCOME TAXES

Income tax benefit (provision) for the indicated periods is comprised of the following (in thousands):

	Successor	Predecessor		
	Period from September 10, 2016 through December 31, 2016	Period from January 1, 2016 through September 9, 2016	Years Ended December 31, 2015	Years Ended December 31, 2014
Current:				
Federal	$ (5,000)	$ 8,666	$ (8,580)	$ 1,295
State	256	—	(506)	(219)
Total current income tax benefit (provision)	(4,744)	8,666	(9,086)	1,076
Deferred:				
Federal	52,223	(22,491)	(39,331)	2,653
State	(52,223)	22,491	39,331	(2,653)
Total deferred income tax benefit (provision)	—	—	—	—
Total income tax benefit (provision)	$ (4,744)	$ 8,666	$ (9,086)	$ 1,076

The actual income tax benefit (provision) differs from the expected income tax benefit (provision) as computed by applying the United States Federal corporate income tax rate of 35% for each period as follows (in thousands):

	Successor	Predecessor		
	Period from September 10, 2016 through December 31, 2016	Period from January 1, 2016 through September 9, 2016	Years Ended December 31, 2015	Years Ended December 31, 2014
Expected tax benefit (provision)	$ 166,057	$ (1,152)	$ 669,737	$(110,208)
State income tax expense, net of federal benefit	6,243	(43)	41,003	(4,615)
Share-based compensation	—	(14,803)	—	—
Net operating loss limitation under IRC Section 382	(161,704)	—	—	—
HK TMS Divestiture	(157,767)	—	—	—
Adjustments attributable to reorganization	—	275,460	—	—
Debt related costs	—	(4,089)	(7,102)	(5,467)
Cancellation of indebtedness income	—	103,268	(89,081)	—
Increase (reduction) in deferred tax asset	—	14,429	(6,369)	19,233
Change in valuation allowance and related items	202,592	(262,995)	(598,429)	102,068
IRC section 108 attribute reduction	(56,483)	(101,342)	(13,744)	—
Other	(3,682)	(67)	(5,101)	65
Total income tax benefit (provision)	$ (4,744)	$ 8,666	$ (9,086)	$ 1,076

14. INCOME TAXES (Continued)

The components of net deferred income tax assets (liabilities) recognized are as follows (in thousands):

	Successor	Predecessor
	December 31, 2016	December 31, 2015
Deferred noncurrent income tax assets:		
Net operating loss carry-forwards	$ 155,393	$ 555,044
Share-based compensation expense	3,430	15,027
Asset retirement obligations	11,233	14,616
Investment in unconsolidated entities	—	59,429
Book-tax differences in property basis	647,574	234,900
Unrealizd hedging transactions	3,937	—
Other	330	19,376
Gross deferred noncurrent income tax assets	821,897	898,392
Valuation allowance	(821,897)	(761,493)
Deferred noncurrent income tax assets	$ —	$ 136,899
Deferred noncurrent income tax liabilities:		
Change in accounting method	$ —	$ (4,057)
Unrealized hedging transactions	—	(132,842)
Other	—	—
Deferred noncurrent income tax liabilities	$ —	$(136,899)
Net noncurrent deferred income tax assets (liabilities)	$ —	$ —

At December 31, 2015, the Company early adopted ASU 2015-07 on a prospective basis and accordingly, presented all deferred tax assets and liabilities as noncurrent on the consolidated balance sheet as of December 31, 2015.

Under the Plan, a substantial portion of the Company's pre-petition debt securities were extinguished. Absent an exception, a debtor recognizes cancellation of indebtedness income (CODI) upon discharge of its outstanding indebtedness for an amount of consideration that is less than its adjusted issue price. The Internal Revenue Code of 1986, as amended (IRC), provides that a debtor in a bankruptcy case may exclude CODI from taxable income but must reduce certain of its tax attributes by the amount of any CODI realized as a result of the consummation of a plan of reorganization. The amount of CODI realized by a taxpayer is the adjusted issue price of any indebtedness discharged less the sum of (i) the amount of cash paid, (ii) the issue price of any new indebtedness issued and (iii) the fair market value of any other consideration, including equity, issued. As a result of the market value of equity upon emergence from chapter 11 bankruptcy proceedings, the estimated amount of U.S. CODI is approximately $844 million, which will reduce the value of the Company's U.S. net operating losses and other assets. The actual reduction in tax attributes does not occur until the first day of the Company's tax year subsequent to the date of emergence, or January 1, 2017. The estimated results of the attribute reduction have been reflected in the Company's ending balance of deferred tax assets for the year ended December 31, 2016 (Successor). The Successor Company also has various state NOL carryforwards that are subject to reduction as a result of the CODI being excluded from taxable income. The Successor Company's state NOL carryforwards after attribute reduction are not expected to be material.

14. INCOME TAXES (Continued)

IRC Section 382 provides an annual limitation with respect to the ability of a corporation to utilize its tax attributes, as well as certain built-in-losses, against future U.S. taxable income in the event of a change in ownership. The Company's emergence from chapter 11 bankruptcy proceedings is considered a change in ownership for purposes of IRC Section 382. The limitation under the IRC is based on the value of the corporation as of the emergence date. The ownership changes and resulting annual limitation will result in the expiration of an estimated $462 million of net operating losses generated prior to the emergence date. The expiration of these tax attributes was fully offset by a corresponding decrease in the Company's U.S. valuation allowance, which results in no net tax provision.

The amount of consolidated U.S. net operating losses (NOLs) available as of December 31, 2016 (Successor) after attribute reduction on January 1, 2017 and Section 382 limitation is estimated to be approximately $444 million. These NOLs will expire in the years 2019 through 2036.

The Company assesses the recoverability of its deferred tax assets each period by considering whether it is more likely than not that all or a portion of the deferred tax assets will not be realized. The Company considers all available evidence (both positive and negative) in determining whether a valuation allowance is required. The Company evaluated possible sources of taxable income that may be available to realize the benefit of deferred tax assets, including projected future taxable income, the reversal of existing temporary differences, taxable income in carryback years and available tax planning strategies in making this assessment. A significant item of objective negative evidence considered was the cumulative book loss over the three-year period ended December 31, 2016 driven primarily by the full cost ceiling impairments over that period which limits the ability to consider other subjective evidence such as the Company's anticipated future growth. As a result of the Company's analysis, it was concluded that as of December 31, 2016 a valuation allowance should continue to be applied against the Company's net deferred tax asset. The Company recorded a valuation allowance as of December 31, 2016 (Successor) of $821.9 million, an increase of $60.4 million from December 31, 2015 (Predecessor). The Company will continue to monitor facts and circumstances in the reassessment of the likelihood that operating loss carryforwards, credits and other deferred tax assets will be utilized.

ASC 740, *Income Taxes* (ASC 740) prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of income tax positions taken or expected to be taken in an income tax return. For those benefits to be recognized, an income tax position must be more-likely-than-not to be sustained upon examination by taxing authorities. The Company has no unrecognized tax benefits for the period of September 10, 2016 through December 31, 2016 (Successor) and January 1, 2016 through September 9, 2016 (Predecessor) and the years ended December 31, 2015 or 2014 (Predecessor).

Generally, the Company's income tax years 2013 through 2016 remain open for federal purposes and are subject to examination by Federal tax authorities. The Company's income tax returns are also subject to audit by the tax authorities in Louisiana, Mississippi, North Dakota, Oklahoma, Texas, Pennsylvania, Ohio and certain other state taxing jurisdictions where the Company has, or previously had, operations. In certain jurisdictions the Company operates through more than one legal entity, each of which may have different open years subject to examination. The open years for state purposes can vary from the normal three year statue expiration period for federal purposes.

The Company recognizes interest and penalties accrued to unrecognized benefits in *"Interest expense and other, net"* in its consolidated statements of operations. For the period of September 10, 2016 through December 31, 2016 (Successor) and January 1, 2016 through September 9, 2016

14. INCOME TAXES (Continued)

(Predecessor) and the years ended December 31, 2015 and 2014 (Predecessor) the Company recognized no interest and penalties.

During the first quarter of 2014 (Predecessor), the Internal Revenue Service commenced an audit of GeoResources' tax returns for the years ending December 31, 2010 through August 1, 2012. The audit closed during April 2015 (Predecessor) resulting in a favorable adjustment to the Company of $0.1 million.

15. EARNINGS PER SHARE

On September 9, 2016, upon emergence from chapter 11 bankruptcy, the Predecessor Company's equity was cancelled and new equity was issued. Refer to Note 2, *"Reorganization,"* for further details.

The following represents the calculation of earnings (loss) per share (in thousands, except per share amounts):

	Successor	Predecessor		
	Period from September 10, 2016 through December 31, 2016	Period from January 1, 2016 through September 9, 2016	Years Ended December 31, 2015	Years Ended December 31, 2014
Basic:				
Net income (loss) available to common stockholders	$ (479,984)	$ (32,794)	$ (2,006,958)	$282,942
Weighted average basic number of common shares outstanding	91,228	120,513	107,531	83,155
Basic net income (loss) per common share	$ (5.26)	$ (0.27)	$ (18.66)	$ 3.40
Diluted:				
Net income (loss) available to common stockholders	$ (479,984)	$ (32,794)	$ (2,006,958)	$282,942
Interest on Convertible Note, net	—	—	—	15,302
Series A preferred dividends	—	—	—	19,838
Net income (loss) available to common stockholders after assumed conversions	$ (479,984)	$ (32,794)	$ (2,006,958)	$318,082
Weighted average basic number of common shares outstanding	91,228	120,513	107,531	83,155
Common stock equivalent shares representing shares issuable upon:				
Exercise of stock options	Anti-dilutive	Anti-dilutive	Anti-dilutive	75
Exercise of February 2012 Warrants	—	Anti-dilutive	Anti-dilutive	784
Exercise of Warrants	Anti-dilutive	—	—	—
Vesting of restricted shares	Anti-dilutive	Anti-dilutive	Anti-dilutive	310
Vesting of performance units	—	—	—	73
Conversion of Convertible Note	—	Anti-dilutive	Anti-dilutive	12,875
Conversion of Series A Preferred Stock	—	Anti-dilutive	Anti-dilutive	11,209
Weighted average diluted number of common shares outstanding	91,228	120,513	107,531	108,481
Diluted net income (loss) per common share	$ (5.26)	$ (0.27)	$ (18.66)	$ 2.93

15. EARNINGS PER SHARE (Continued)

Common stock equivalents, including stock options, restricted shares and warrants totaling 11.2 million shares for the period from September 10, 2016 through December 31, 2016 (Successor) were not included in the computation of diluted earnings per share of common stock because the effect would have been anti-dilutive. Common stock equivalents, including stock options, restricted shares, warrants, convertible debt and preferred stock totaling 43.6 million shares for the period from January 1, 2016 through September 9, 2016 (Predecessor) were not included in the computation of diluted earnings per share of common stock because the effect would have been anti-dilutive.

On January 24, 2017 (Successor), the Company entered into a stock purchase agreement with certain accredited investors to sell approximately 5,518 shares of 8% automatically convertible preferred stock, each share of which is convertible into 10,000 shares of common stock (or a proportionate number of shares of common stock with respect to any fractional shares of preferred stock issued). Refer to Note 17, "*Subsequent Events,*" for further details.

Common stock equivalents, including stock options, restricted shares, warrants, convertible debt and preferred stock totaling 47.1 million shares were not included in the computation of diluted earnings per share of common stock because the effect would have been anti-dilutive for the year ended December 31, 2015 (Predecessor) due to the net loss.

Common stock equivalents, including stock options, restricted shares and warrants, totaling 6.2 million shares were not included in the computation of diluted earnings per share of common stock because the effect would have been anti-dilutive for the year ended December 31, 2014 (Predecessor).

16. ADDITIONAL FINANCIAL STATEMENT INFORMATION

Certain balance sheet amounts are comprised of the following (in thousands):

	Successor	Predecessor
	December 31, 2016	December 31, 2015
Accounts receivable:		
Oil, natural gas and natural gas liquids revenues	$ 86,433	$ 55,129
Joint interest accounts	39,828	67,626
Accrued settlements on derivative contracts	18,599	47,011
Affiliated partnership	268	176
Other	2,634	3,682
	$147,762	$173,624
Prepaids and other:		
Prepaids	$ 6,704	$ 4,585
Inventory	—	4,635
Other	54	50
	$ 6,758	$ 9,270
Accounts payable and accrued liabilities:		
Trade payables	$ 24,364	$ 47,261
Accrued oil and natural gas capital costs	32,967	54,651
Revenues and royalties payable	79,147	64,002
Accrued interest expense	31,146	88,499
Accrued employee compensation	3,428	2,829
Accrued lease operating expenses	14,077	20,036
Drilling advances from partners	422	7,964
Income taxes payable	250	9,172
Affiliated partnership	323	365
Other	60	306
	$186,184	$295,085

17. SUBSEQUENT EVENTS

Issuance of 2025 Senior Notes and Repurchase of 2020 Second Lien Notes

On February 16, 2017 (Successor), the Company issued $850.0 million aggregate principal amount of new 6.75% senior unsecured notes due 2025 (the 2025 Notes) in a private placement exempt from registration under the Securities Act of 1933, as amended (Securities Act), afforded by Rule 144A and Regulation S, and applicable state securities laws. The 2025 Notes were issued at par and bear interest at a rate of 6.75% per annum, payable semi-annually on February 15 and August 15 of each year, beginning on August 15, 2017. The 2025 Notes will mature on February 15, 2025. Proceeds from the private placement were approximately $835.1 million after deducting initial purchasers' discounts and commissions and offering expenses. The Company used a portion of the net proceeds from the private placement to fund the repurchase of the outstanding 2020 Second Lien Notes, and will use an additional amount of the net proceeds to redeem the remaining amount of such notes, discussed further below, and for general corporate purposes.

The 2025 Notes are governed by an Indenture, dated as of February 16, 2017, (the February 2017 Indenture) by and among the Company, the Guarantors and U.S. Bank National Association, as

17. SUBSEQUENT EVENTS (Continued)

Trustee, which contains affirmative and negative covenants that, among other things, limit the ability of the Company and the Guarantors to incur indebtedness; purchase or redeem stock or subordinated indebtedness; make investments; create liens; enter into transactions with affiliates; sell assets; refinance certain indebtedness; merge with or into other companies or transfer substantially all of their assets; and, in certain circumstances, to pay dividends or make other distributions on stock. The February 2017 Indenture also contains customary events of default. Upon the occurrence of certain events of default, the Trustee or the holders of the 2025 Notes may declare all outstanding 2025 Notes to be due and payable immediately. The 2025 Notes are fully and unconditionally guaranteed on a senior basis by the Guarantors and by certain future subsidiaries of the Company.

In connection with the sale of the 2025 Notes, on February 16, 2017, the Company, the Guarantors and J.P. Morgan Securities LLC, on behalf of itself and as representative of the Initial Purchasers, entered into a Registration Rights Agreement (the 2017 Registration Rights Agreement) pursuant to which the Company agreed to, among other things, use reasonable best efforts to file a registration statement under the Securities Act and complete an exchange offer for the 2025 Notes within 365 days after closing.

At any time prior to February 15, 2020, the Company may redeem the 2025 Notes, in whole or in part, at a redemption price equal to 100% of their principal amount plus a make-whole premium, together with accrued and unpaid interest, if any, to the redemption date. The 2025 Notes will be redeemable, in whole or in part, on or after February 15, 2020 at redemption prices equal to the principal amount multiplied by the percentage set forth below, plus accrued and unpaid interest (if any) on the 2025 Notes redeemed during the twelve month period indicated beginning on February 15 of the years indicated below:

Year	Percentage
2020	105.063
2021	103.375
2022	101.688
2023 and thereafter	100.000

Additionally, the Company may redeem up to 35% of the 2025 Notes prior to February 15, 2020 for a redemption price of 106.75% of the principal amount thereof, plus accrued and unpaid interest, utilizing net cash proceeds from certain equity offerings. In addition, upon a change of control of the Company, holders of the 2025 Notes will have the right to require the Company to repurchase all or any part of their 2025 Notes for cash at a price equal to 101% of the aggregate principal amount of the 2025 Notes repurchased, plus any accrued and unpaid interest.

On February 9, 2017 (Successor), the Company commenced a cash tender offer for any and all of its 2020 Second Lien Notes and on February 15, 2017, the Company received approximately $289.2 million or 41% of the outstanding aggregate principal amount of the 2020 Second Lien Notes which were validly tendered (and not validly withdrawn). As a result, on February 16, 2017 (Successor), the Company paid approximately $303.5 million for approximately $289.2 million principal amount of 2020 Second Lien Notes, a make-whole premium of $13.2 million plus accrued and unpaid interest of approximately $1.1 million to repurchase such notes and issued a redemption notice to redeem the remaining 2020 Second Lien Notes. The remaining $410.8 million aggregate principal amount of 2020 Second Lien Notes will be repurchased through the guaranteed delivery procedures or redeemed at a

17. SUBSEQUENT EVENTS (Continued)

price of 104.313% of the principal amount thereof, plus accrued and unpaid interest to, but not including, the redemption date. The redemption date is expected to be March 20, 2017.

Pending Divestiture of East Texas Eagle Ford Assets

On January 24, 2017 (Successor), certain of the Company's subsidiaries entered into an Agreement of Sale and Purchase with a subsidiary of Hawkwood Energy, LLC (Hawkwood) for the sale of all of its oil and natural gas properties and related assets located in the Eagle Ford formation of East Texas (the El Halcón Assets) for a total sales price of $500.0 million (the El Halcón Divestiture). The effective date of the proposed sale is January 1, 2017, and the Company expects to close the transaction in early March 2017. The sale properties include approximately 80,500 net acres prospective for the Eagle Ford formation in East Texas and the related gas gathering assets.

The sales price is subject to adjustments for (i) operating expenses, capital expenditures and revenues between the effective date and the closing date, (ii) title, casualty and environmental defects, and (iii) other purchase price adjustments customary in oil and gas purchase and sale agreements. Pursuant to the terms of the agreement, Hawkwood paid into escrow a deposit of $32.5 million at signing, which amount will be applied to the sales price if the transaction closes.

The completion of the El Halcón Divestiture is subject to customary closing conditions. The parties may terminate the sale agreement if certain closing conditions have not been satisfied, if total adjustments to the sales price exceed 20% of the sales price, or $100.0 million, or the transaction has not closed on or before March 20, 2017. If one or more of the closing conditions are not satisfied, or if the transaction is otherwise terminated, the divestiture may not be completed. There can be no assurance that the Company will sell the El Halcón Assets on the terms or timing described or at all. If the El Halcón Divestiture closes, the Company intends to use the net proceeds to repay borrowings outstanding under its Senior Credit Agreement and for general corporate purposes.

Private Placement of Automatically Convertible Preferred Stock

On January 24, 2017 (Successor), the Company entered into a stock purchase agreement with certain accredited investors to sell, in a private placement exempt from registration requirements of the Securities Act pursuant to Section 4(a)(2), approximately 5,518 shares of 8% automatically convertible preferred stock, par value $0.0001 per share, each share of which is convertible into 10,000 shares of common stock, par value $0.0001 per share (or a proportionate number of shares of common stock with respect to any fractional shares of preferred stock issued), for gross proceeds of approximately $400.1 million, equivalent to a placement at $7.25 per common share. The Company used the net proceeds from the sale of the preferred stock to partially fund the Pecos County Acquisition.

The preferred stock was offered and sold in a private placement exempt from the registration requirements of the Securities Act pursuant to Section 4(a)(2) to "accredited investors" (as defined in Rule 501(a) under the Securities Act).

Each share of preferred stock will be convertible into a number of shares of common stock determined by dividing the liquidation preference of the preferred stock, which is equal to the liquidation price plus the amount of any accrued and unpaid dividends through the date of conversion, by the conversion price. The aggregate liquidation preference of the preferred stock is $400.1 million. Accordingly, until such date each share of preferred stock will automatically convert into 10,000 shares

17. SUBSEQUENT EVENTS (Continued)

of common stock at an initial conversion price of $7.25 per share of common stock and each fractional share of preferred stock will be initially convertible into a proportionate number of shares of common stock. The preferred stock will convert automatically on the 20th calendar day after the Company mails a definitive information statement to holders of its common stock notifying them that holders of a majority of its outstanding common stock consented to the issuance of common stock upon conversion of the preferred stock on as of January 24, 2017 (Successor). The initial conversion price is subject to adjustment in certain circumstances, including stock splits, stock dividends, rights offerings, or combinations of its common stock. No dividend will be paid on the preferred stock if it converts into common stock on or before June 1, 2017. The common stock issuable upon a conversion of the preferred stock represents approximately 37% of the Company's outstanding common stock as of December 31, 2016 on an as-converted basis.

The Company agreed to file a registration statement to register the resale of shares of common stock issuable upon conversion of the preferred stock and to pay penalties in the event such registration is not effective by June 27, 2017.

Acquisition of Southern Delaware Basin Assets (Pecos and Reeves Counties, Texas)

On January 18, 2017 (Successor), Halcón Energy Properties, Inc., a wholly owned subsidiary of the Company, entered into a Purchase and Sale Agreement with Samson Exploration, LLC (Samson), pursuant to which it agreed to acquire a total of 20,901 net acres and related assets in the Southern Delaware Basin located in Pecos and Reeves Counties, Texas (collectively, the Pecos County Assets), for a total purchase price of $705.0 million (the Pecos County Acquisition). The effective date of the acquisition was November 1, 2016, and the Company closed the transaction on February 28, 2017.

The purchase price was subject to adjustments for (i) operating expenses, capital expenditures and revenues between the effective date and the closing date, (ii) title, casualty and environmental defects, and (iii) other purchase price adjustments customary in oil and gas purchase and sale agreements. The Company funded the Pecos County Acquisition with the net proceeds from the private placement of its preferred stock and borrowings under its Senior Credit Agreement.

Following the agreement with Samson, the Company agreed to acquire additional interests in the acreage from a non-operating owner for approximately $22.3 million. This incremental acquisition includes 594 additional net acres and is expected to close in early March 2017.

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

Oil and Natural Gas Reserves

Users of this information should be aware that the process of estimating quantities of "proved" and "proved developed" oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various reservoirs make these estimates generally less precise than other estimates included in the financial statement disclosures.

Proved reserves represent estimated quantities of natural gas, crude oil and condensate and natural gas liquids that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions in effect when the estimates were made. Proved developed reserves are proved reserves expected to be recovered through wells and equipment in place and under operating methods used when the estimates were made.

The proved reserves estimates shown herein for the years ended December 31, 2016 (Successor), 2015 (Predecessor) and 2014 (Predecessor) have been independently evaluated by Netherland, Sewell, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. Netherland, Sewell was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within Netherland, Sewell, the technical persons primarily responsible for preparing the estimates set forth in the Netherland, Sewell reserves report incorporated herein are Mr. J. Carter Henson, Jr. and Mr. Mike K. Norton. Mr. Henson, a Licensed Professional Engineer in the State of Texas (No. 73964), has been practicing consulting petroleum engineering at Netherland, Sewell since 1989 and has over 8 years of prior industry experience. He graduated from Rice University in 1981 with a Bachelor of Science Degree in Mechanical Engineering. Mr. Norton, a Licensed Professional Geoscientist in the State of Texas (No. 441), has been a practicing petroleum geoscience consultant at Netherland, Sewell since 1989 and has over ten years of prior industry experience. He graduated from Texas A&M University in 1978 with a Bachelor of Science Degree in Geology. Netherland, Sewell has reported to the Company, that 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.

The Company's board of directors has established an independent reserves committee composed of three outside directors, all of whom have experience in energy company reserve evaluations. The Company's independent engineering firm reports jointly to the reserves committee and to the Senior Vice President of Corporate Reserves. The reserves committee is charged with ensuring the integrity of the process of selection and engagement of the independent engineering firm and in making a recommendation to the board of directors as to whether to approve the report prepared by the independent engineering firm. Ms. Tina Obut, the Company's Senior Vice President of Corporate Reserves is primarily responsible for overseeing the preparation of the annual reserve report by Netherland, Sewell. She graduated from Marietta College with a Bachelor of Science degree in Petroleum Engineering, received a Master of Science degree in Petroleum and Natural Gas

Engineering from Penn State University and a Master of Business Administration degree from the University of Houston.

The reserves information in this Annual Report on Form 10-K represents only estimates. There are a number of uncertainties inherent in estimating quantities of proved reserves, including many factors beyond the Company's control, such as commodity pricing. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. 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 may vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may lead to revising the original estimate. Accordingly, initial reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. The meaningfulness of such estimates depends primarily on the accuracy of the assumptions upon which they were based. Except to the extent the Company acquires additional properties containing proved reserves or conducts successful exploration and development activities or both, the Company's proved reserves will decline as reserves are produced.

The following table illustrates the Company's estimated net proved reserves, including changes, and proved developed reserves for the periods indicated. The oil and natural gas liquids prices as of December 31, 2016, 2015 and 2014 are based on the respective 12-month unweighted average of the first of the month prices of the West Texas Intermediate spot price which equates to $42.75 per barrel, $50.28 per barrel and $94.99 per barrel, respectively. The natural gas prices as of December 31, 2016, 2015 and 2014 are based on the respective 12-month unweighted average of the first of the month prices of the Henry Hub spot price which equates to $2.481 per MMBtu, $2.587 per MMBtu and $4.350 per MMBtu, respectively. All prices are adjusted by lease or field for energy content, transportation fees, and market differentials. All prices are held constant in accordance with SEC guidelines. All proved reserves are located in the United States.

	Proved Reserves			
	Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Equivalent (MBoe)
Proved reserves, December 31, 2013 (Predecessor)	114,510	69,748	9,832	135,967
Extensions and discoveries	61,312	31,937	5,984	72,619
Purchase of minerals in place	942	767	45	1,115
Production	(12,787)	(8,812)	(1,113)	(15,369)
Sale of minerals in place	(14,487)	(8,125)	(1,789)	(17,630)
Revision of previous estimates	6,084	18,147	3,327	12,435
Proved reserves, December 31, 2014 (Predecessor)	155,574	103,662	16,286	189,137
Extensions and discoveries	10,117	6,838	1,215	12,472
Purchase of minerals in place	36	17	4	43
Production	(12,019)	(10,123)	(1,457)	(15,163)
Sale of minerals in place	(5)	(2)	(1)	(6)
Revision of previous estimates	(33,010)	(21,950)	(3,010)	(39,679)
Proved reserves, December 31, 2015 (Predecessor)	120,693	78,442	13,037	146,804
Extensions and discoveries	15,279	7,532	1,722	18,256
Purchase of minerals in place	1,114	654	113	1,336
Production	(10,368)	(9,571)	(1,597)	(13,560)
Sale of minerals in place	(1,319)	(258)	(7)	(1,369)
Revision of previous estimates	(5,799)	3,439	2,373	(2,853)
Proved reserves, December 31, 2016 (Successor)	119,600	80,238	15,641	148,614

	Proved Developed Reserves			
	Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Equivalent (MBoe)
December 31, 2016 (Successor)	67,983	51,525	9,337	85,908
December 31, 2015 (Predecessor)	66,123	49,201	7,561	81,885
December 31, 2014 (Predecessor)	62,770	47,851	6,681	77,427

	Proved Undeveloped Reserves			
	Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Equivalent (MBoe)
December 31, 2016 (Successor)	51,617	28,713	6,304	62,706
December 31, 2015 (Predecessor)	54,570	29,241	5,476	64,919
December 31, 2014 (Predecessor)	92,804	55,811	9,605	111,710

The Company's reserves have been estimated using deterministic methods. The total proved reserve increase of 1.8 MMBoe during 2016 is the result of an increase in proved developed reserves of 4.0 MMBoe offset by a decrease of 2.2 MMBoe in proved undeveloped (PUD) reserves.

During 2016, the increase in proved developed reserves is primarily associated with extension and infill drilling in the Bakken / Three Forks and El Halcón areas and positive performance revisions in the Bakken / Three Forks area partially offset by negative revisions due to lower SEC prices. The decrease in PUD reserves is primarily due to the conversion of PUD reserves to proved developed reserves from infill drilling and the removal of PUDs that no longer met the SEC five year development requirement, partially offset by the addition of PUD reserves.

During 2015, the Predecessor Company added 12.5 MMBoe in proved reserves by drilling extensions and infill development primarily in the Bakken / Three Forks and El Halcón areas. Extensions and discoveries were offset by negative revisions due to the sustained decline in commodity prices, resulting in an overall negative revision of 39.7 MMBoe.

During 2014, the Predecessor Company added 72.6 MMBoe in proved reserves by drilling extensions and infill development in the Bakken / Three Forks and El Halcón areas and an additional 12.4 MMBoe in positive revisions driven by better performance in the Bakken / Three Forks area. Sales of 17.6 MMBoe of proved reserves are primarily attributable to the divestiture of the East Texas Assets.

At December 31, 2016, the Successor Company's estimated PUD reserves were approximately 62.7 MMBoe, a 2.2 MMBoe net decrease over the previous year's estimate of 64.9 MMBoe. The following details the changes in PUD reserves for 2016 (MBoe):

Beginning proved undeveloped reserves at December 31, 2015 (Predecessor)	64,919
Undeveloped reserves transferred to developed	(7,510)
Revisions	(9,314)
Purchases	526
Divestitures	(246)
Extension and discoveries	14,331
Ending proved undeveloped reserves at December 31, 2016 (Successor)	62,706

The decrease in PUD reserves was due to a negative revision associated with the decline in the unweighted 12-month average prices of oil and natural gas during 2016. Negative revisions of approximately 9 MMBoe were largely associated with PUD locations in the Bakken/Three Forks and El Halcón areas that became uneconomic at the lower unweighted 12-month average prices of oil and natural gas as of December 31, 2016 (Successor), or were removed because they no longer met the

SEC five year development requirement as we have reduced our capital spending since the prior year as a result of the sustained decline in oil and natural gas prices. Further reductions of approximately 8 MMBoe in PUD reserves were the direct result of development through our drilling program and the associated transfer of those reserves to proved developed reserves, primarily in the Bakken/Three Forks and El Halcón areas.

As of December 31, 2016 all of the Successor Company's PUD reserves are planned to be developed within five years from the date they were initially recorded. During 2016, approximately $181.7 million in capital expenditures went toward the development of proved undeveloped reserves, which includes drilling, completion and other facility costs associated with developing proved undeveloped wells.

For wells classified as proved developed producing where sufficient production history existed, reserves were based on individual well performance evaluation and production decline curve extrapolation techniques. For undeveloped locations and wells that lacked sufficient production history, reserves were based on analogy to producing wells within the same area exhibiting similar geologic and reservoir characteristics, combined with volumetric methods. The volumetric estimates were based on geologic maps and rock and fluid properties derived from well logs, core data, pressure measurements, and fluid samples. Well spacing was determined from drainage patterns derived from a combination of performance-based recoveries and volumetric estimates for each area or field. PUD locations were limited to areas of uniformly high quality reservoir properties, between existing commercial producers.

Reliable technologies were used to determine areas where PUD locations are more than one offset location away from a producing well. These technologies include seismic data, wire line open hole log data, core data, log cross-sections, performance data, and statistical analysis. In such areas, these data demonstrated consistent, continuous reservoir characteristics in addition to significant quantities of economic EURs from individual producing wells. The Company's management team has been a leader in data gathering and evaluation in these areas and was instrumental in developing consortiums that allow various operators to exchange data. The Company relied only on production flow tests and historical production data, along with the reliable geologic data mentioned above to estimate proved reserves. No other alternative methods or technologies were used to estimate proved reserves.

Capitalized Costs Relating to Oil and Natural Gas Producing Activities

The following table illustrates the total amount of capitalized costs relating to oil and natural gas producing activities and the total amount of related accumulated depletion, depreciation and accretion (in thousands):

	Successor	Predecessor	
	December 31, 2016	December 31, 2015	December 31, 2014
Evaluated oil and natural gas properties[1]	$1,269,034	$ 7,060,721	$ 6,390,820
Unevaluated oil and natural gas properties	316,439	1,641,356	1,829,786
	1,585,473	8,702,077	8,220,606
Accumulated depletion[1]	(465,849)	(5,933,688)	(2,953,038)
	$1,119,624	$ 2,768,389	$ 5,267,568

(1) Amounts do not include costs for the Company's gas gathering systems and related support equipment.

Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration and Development Activities

Costs incurred in property acquisition, exploration and development activities were as follows:

	Successor	Predecessor		
	Period from September 10, 2016 through December 31, 2016	Period from January 1, 2016 through September 9, 2016	Years Ended December 31, 2015	2014
		(In thousands)		
Property acquisition costs, proved[(1)]	$ —	$ (127)	$ (582)	$ 16,037
Property acquisition costs, unproved	5,070	3	268	220,044
Exploration and extension well costs	13,865	67,216	194,683	1,107,549
Development costs	45,765	135,939	285,194	374,252
Total costs	$64,700	$203,031	$479,563	$1,717,882

(1) Proved property acquisition costs in 2016 and 2015 primarily reflect the impact of purchase price adjustments.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves

The following Standardized Measure of Discounted Future Net Cash Flows (Standardized Measure) has been developed utilizing ASC 932, *Extractive Activities—Oil and Gas* (ASC 932) procedures and based on oil and natural gas reserve and production volumes estimated by the Company's engineering staff. It can be used for some comparisons, but should not be the only method used to evaluate the Company or its performance. Further, the information in the following table may not represent realistic assessments of future cash flows, nor should the Standardized Measure be viewed as representative of the current value of the Company.

The Company believes that the following factors should be taken into account when reviewing the following information:

- future costs and selling prices will probably differ from those required to be used in these calculations;
- due to future market conditions and governmental regulations, actual rates of production in future years may vary significantly from the rate of production assumed in the calculations;
- a 10% discount rate may not be reasonable as a measure of the relative risk inherent in realizing future net oil and natural gas revenues; and
- future net revenues may be subject to different rates of income taxation.

At December 31, 2016, 2015 and 2014, as specified by the SEC, the prices for oil and natural gas used in this calculation were the unweighted 12-month average of the first day of the month prices, except for volumes subject to fixed price contracts. Estimates of future income taxes are computed using current statutory income tax rates including consideration for estimated future statutory depletion and tax credits. The resulting net cash flows are reduced to present value amounts by applying a 10% discount factor.

The Standardized Measure is as follows:

	Years Ended December 31,		
	2016	2015	2014
		(In thousands)	
Future cash inflows	$ 4,726,490	$ 5,406,179	$14,439,301
Future production costs	(2,290,079)	(2,414,629)	(4,804,728)
Future development costs	(771,070)	(813,814)	(2,795,208)
Future income tax expense	—	—	(1,979,245)
Future net cash flows before 10% discount	1,665,341	2,177,736	4,860,120
10% annual discount for estimated timing of cash flows	(861,824)	(1,067,171)	(1,603,750)
Standardized measure of discounted future net cash flows	$ 803,517	$ 1,110,565	$ 3,256,370

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves

The following is a summary of the changes in the Standardized Measure for the Company's proved oil and natural gas reserves during each of the years in the three year period ended December 31, 2016:

	Years Ended December 31,		
	2016	2015	2014
		(In thousands)	
Beginning of year	$1,110,565	$ 3,256,370	$2,745,995
Sale of oil and natural gas produced, net of production costs	(275,816)	(375,137)	(893,117)
Purchase of minerals in place	9,626	946	22,142
Sales of minerals in place	(18,816)	(96)	(475,096)
Extensions and discoveries	67,433	94,679	1,298,611
Changes in income taxes, net	—	170,546	(151,690)
Changes in prices and costs	(302,064)	(2,452,581)	64,467
Previously estimated development costs incurred	66,087	295,258	424,504
Net changes in future development costs	46,981	456,726	(10,774)
Revisions of previous quantities	20,192	(718,932)	226,499
Accretion of discount	111,056	342,692	276,485
Changes in production rates and other	(31,727)	40,094	(271,656)
End of year	$ 803,517	$ 1,110,565	$3,256,370

SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

Prior year financial statements are not comparable to our current year financial statements due to the adoption of fresh-start accounting. References to "Successor" or "Successor Company" relate to the financial position and results of operations of the reorganized company subsequent to September 9, 2016. References to "Predecessor" or "Predecessor Company" relate to the financial position and results of operations of the reorganized company prior to, and including, September 9, 2016.

The following table presents selected quarterly financial data derived from the Company's unaudited consolidated interim financial statements. The following data is only a summary and should be read with the Company's historical consolidated financial statements and related notes contained in this document (in thousands, except per share amounts).

	Predecessor			Successor	
	Quarter Ended March 31	Quarter Ended June 30	Period from July 1, 2016 through September 9, 2016	Period from September 10, 2016 through September 30, 2016	Quarter Ended December 31
2016					
Total operating revenues	$ 81,349	$ 106,147	$ 79,347	$ 23,107	$130,255
Income (loss) from operations	(592,384)	(261,458)	2,225	(433,725)	17,926
Net income (loss)	(539,999)	(374,303)	926,260	(450,692)	(28,501)
Net income (loss) available to common stockholders[(1)]	(566,862)	(382,353)	916,421	(451,483)	(28,501)
Net income (loss) per share of common stock:					
Basic	$ (4.72)	$ (3.17)	$ 7.58	$ (4.96)	$ (0.31)
Diluted	$ (4.72)	$ (3.17)	$ 6.06	$ (4.96)	$ (0.31)

	Predecessor			
	Quarters Ended			
	March 31	June 30	September 30	December 31
2015				
Total operating revenues	$ 136,194	$ 168,024	$ 129,939	$ 116,121
Income (loss) from operations	(626,169)	(954,387)	(528,685)	(635,265)
Net income (loss)	(587,641)	(1,088,612)	147,075	(393,443)
Net income (loss) available to common stockholders[(2)]	(601,193)	(1,104,581)	123,528	(424,712)
Net income (loss) per share of common stock:				
Basic				
Diluted	$ (7.16)	$ (10.13)	$ 1.05	$ (3.56)
	$ (7.16)	$ (10.13)	$ 0.88	$ (3.56)

(1) *The volatility in "Net income (loss) available to common stockholders" is substantially due to a) the Company's reorganization and associated fresh-start accounting, (b) the Company's full cost ceiling impairments, c) the gains on the extinguishment of debt and d) the Company's realized and unrealized gains and losses on its derivative contracts. See footnotes for additional information.*

(2) *The volatility in "Net income (loss) available to common stockholders" is substantially due to a) the Company's full cost ceiling impairments, b) the gains on the extinguishment of debt and c) the Company's realized and unrealized gains and losses on its derivative contracts. See footnotes for additional information.*

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Management's Evaluation of Disclosure Controls and Procedures

In accordance with Rules 13a-15(f) and 15d-15(f), of the Exchange Act, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of our disclosure controls and procedures based on the *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013 as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2016 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Our disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Management's Report on Internal Control over Financial Reporting

Management has assessed, and our independent registered public accounting firm, Deloitte & Touche LLP, has audited, our internal control over financial reporting as of December 31, 2016. The unqualified reports of management and Deloitte & Touche LLP thereon are included in Item 8. *Consolidated Financial Statements and Supplementary Data* of this Annual Report on Form 10-K and are incorporated by reference herein.

Changes in Internal Control over Financial Reporting

There has been no change in our internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act, during the three months ended December 31, 2016 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The Board of Directors

Our business and affairs are managed under the direction of our board of directors, or board. Our bylaws specify that we shall not have less than one nor more than fifteen directors, and our board currently has nine members. Under our bylaws and our certificate of incorporation, each director holds office until the next annual meeting of stockholders at which such director's class stands for re-election and serves until the director's successor is duly elected and qualified, or until such director's earlier death, resignation or removal. Our certificate of incorporation provides that our board is classified into three classes: Class A, Class B and Class C, each class having a three-year term of office.

On July 27, 2016, the Company and certain of its subsidiaries filed voluntary petitions for relief under chapter 11 of the United States Bankruptcy Code in the U.S. Bankruptcy Court in the District of Delaware (the "Bankruptcy Court") to pursue a joint prepackaged plan of reorganization (the "Reorganization Plan"). On September 8, 2016, the Bankruptcy Court entered an order confirming the Reorganization Plan and on September 9, 2016, the Plan became effective (the "Reorganization Plan Effective Date") and the Company emerged from chapter 11 bankruptcy. We refer to this transaction as the "Reorganization."

In connection with the Reorganization and in accordance with the Reorganization Plan, upon the Reorganization Plan Effective Date, Floyd C. Wilson, William J. Campbell, James W. Christmas, Michael L. Clark, Thomas R. Fuller, Darryl L. Schall, Ronald D. Scott, Eric G. Takaha and Nathan W. Walton, were appointed as directors.

The following table sets forth the names and ages of all of our current directors, the positions and offices with us held by such persons, the years in which their current terms as directors expire and the length of their continuous service as a director:

Name	Director Since	Age	Position	Expiration of Term
Floyd C. Wilson	Feb. 2012	70	Chairman of the Board, Chief Executive Officer and President	2017
William J. Campbell	Sep. 2016	58	Director	2018
James W. Christmas	Feb. 2012	68	Lead Director	2018
Michael L. Clark	Sep. 2016	45	Director	2018
Thomas R. Fuller	Feb. 2012	69	Director	2017
Darryl L. Schall	Sep. 2016	56	Director	2019
Ronald D. Scott	Sep. 2016	58	Director	2018
Eric G. Takaha.	Sep. 2016	50	Director	2019
Nathan W. Walton	Sep. 2016	39	Director	2019

Floyd C. Wilson has served as Chairman, Chief Executive Officer and President since February 2012. Mr. Wilson served as Chairman of the Board and Chief Executive Officer of Petrohawk Energy Corporation from May 2004 until BHP Billiton acquired Petrohawk in August 2011. Mr. Wilson also served as President of Petrohawk from May 2004 until September 2009. Mr. Wilson was the Chairman and Chief Executive Officer of 3TEC Energy Corporation from August 1999 until its merger with Plains Exploration & Production Company in June 2003. Mr. Wilson founded W/E Energy Company L.L.C., formerly known as 3TEC Energy Company L.L.C. in 1998 and served as its President until August 1999. Mr. Wilson began his career in the energy business in Houston, Texas in 1970 as a completion engineer. He moved to Wichita, Kansas in 1976 to start an oil and gas operating company, one of several private energy ventures which preceded the formation of Hugoton Energy Corporation in 1987, where he served as Chairman, President and Chief Executive Officer. In 1994, Hugoton completed an initial public offering and was merged into Chesapeake Energy Corporation in 1998. Mr. Wilson's qualifications to serve on the board include his role as the Company's Chief Executive Officer and President, his extensive technical experience and wealth of knowledge in the energy industry as well as his many years of service in a leadership role, as a director, chief executive officer and president of oil and natural gas exploration and production companies provide significant contributions to the Company's board.

William J. Campbell has served as a director since the Reorganization in September 2016 and currently serves as Chairman of the Compensation Committee and as a member of the Nominating and Corporate Governance Committee. Mr. Campbell is the Managing Director and Co-owner of CB Energy, LLC, an independent oil and gas exploration company founded in 1997. He has over thirty two years of experience in the legal, investment and energy industries with a diverse background in management, finance, legal, land and marketing. Since 2006, Mr. Campbell has served as owner and managing director of PPPCo-CB Energy, LLC, a Houston, Texas-based private oil and gas exploration and production company. From 1991 to 1996, Mr. Campbell served as Principal, Vice President and Corporate Counsel of Houston, Texas-based Fremont Energy Corporation, a Bechtel Family company, where Mr. Campbell managed the company's domestic and international energy asset portfolio and directed the company's commercial, banking, and legal activities, and from 1985 through 1991, Mr. Campbell served as Counsel and Manager for Bechtel Investments, Inc. in Houston, Texas, managing its oil and gas marketing and land/legal operations. Mr. Campbell was also the first representative of Bechtel in the J.P. Morgan Corporate Finance Program, New York, New York (1988). In addition, Mr. Campbell represented Bechtel's outside oil and gas interests by serving as a Director on the boards of BecField Drilling Services, the then largest independent horizontal and directional drilling company in the United States, CurveDrill, Inc. and PetroSource Corporation, a refining and marketing company with annual revenues over $500 million. Mr. Campbell started his professional career at the Houston, Texas law firm of Reynolds, Allen & Cook. Mr. Campbell has a Doctorate of Jurisprudence (J.D.) and holds a Bachelor of Business Administration Degree (BBA) in Petroleum Land Management/Finance from the University of Texas in Austin, Texas. Mr. Campbell is active in community and civic affairs. His service includes: The Kinkaid School Board of Trustees of Houston since 2007, and its Advancement, Finance & Building Committees since 2002; the Board of Directors of the Houston Country Club from 2005 to 2007; the Institute for Molecular Medicine as a Founding Trustee and Scientific Advisory Board Member since 2001; the Development Board of the University of Texas Health Science Center since 1991- Chair Emeritus 2002-2003; the Advisory Boards of Tanglewood Bank, NA and the Amegy Bank of Texas, N.A. since 1998; the Endowment Board, Jr. Warden and Senior Council Representative of St. Martin's Episcopal Church since 2004; the Board of Directors and Treasurer of the Daniel and Edith Ripley Foundation since 2005; the Board of Directors of the Bayou City Pump Inc. since 2010; the Board of Directors of Erin Energy Corporation and its Audit and Compensation Committees since 2011; the Advance Team Board of M.D. Anderson since 2005; the Texas Children's Hospital Individuals Committee since 2005; the Memorial Hermann System Board of Directors and its Finance and Chairman-Governance Committees and Memorial Hermann Foundation since 2011 and a Member of the Texas Bar Association. Mr. Campbell's qualifications to serve on the board include over thirty years of experience in the legal, investment and energy industries, management of domestic and international energy asset portfolios and extensive professional background provide valuable contributions to the Company's board.

James W. Christmas has served as a director since February 2012 and currently serves as Lead Independent Director, a position he has held since January 2015, as Chairman of the Audit Committee and as a member of the Compensation Committee. Mr. Christmas began serving as a director of Petrohawk Energy Corporation on July 12, 2006, effective upon the merger of KCS Energy, Inc. ("KCS") into Petrohawk. He continued to serve as a director, and as Vice Chairman of the Board of Directors, for Petrohawk until BHP Billiton acquired all of Petrohawk in August 2011. He also served on the Audit Committee and the Nominating and Corporate Governance Committee. Mr. Christmas served as a member of the Board of Directors of Petrohawk, a wholly-owned subsidiary of BHP Billiton, and as chair of the Financial Reporting Committee of such board until September 2014. He also serves on the Advisory Board of the Tobin School of Business of St. John's University. Mr. Christmas serves as a director of Rice Energy, as chairman of its audit committee and a member of its compensation committee, and as a director, chairman of the audit committee and a member of the nominating committee of Yuma Energy. He served as President and Chief Executive Officer of KCS from 1988 until April 2003 and Chairman of the Board and Chief Executive Officer of KCS until its merger into Petrohawk. Mr. Christmas was a Certified Public Accountant in New York and was with Arthur Andersen & Co. from 1970 until 1978 before leaving to join National Utilities & Industries ("NUI"), a diversified energy company, as Vice President and Controller. He remained with NUI until 1988, when NUI spun out its unregulated activities that ultimately became part of KCS. As an auditor and audit manager, controller and in his role as CEO of KCS, Mr. Christmas was directly or indirectly responsible for financial reporting and compliance with SEC regulations, and as such has extensive experience in reviewing and evaluating financial reports, as well as in evaluating executive and board performance and in recruiting directors. Mr. Christmas's qualifications to serve on the board include his experience as an executive, service as director and committee member combined with his extensive audit, accounting and financial reporting experience provide significant contributions to the Company's board.

Michael L. Clark has served as a director since the Reorganization in September 2016 and currently serves as Chairman of the Nominating and Corporate Governance Committee and as a member of the Audit Committee and Compensation Committee. Mr. Clark is a Chartered Financial Analyst (CFA) Charterholder with over seventeen years of investing experience focusing on basic materials and oilfield services and equipment equities. Mr. Clark was a Retired Partner of SIR Capital Management, LLC from 2014 until his departure in 2016 and from 2008 to 2013 served as a Portfolio Manager and Partner. Prior to that, Mr. Clark valued energy equities as a Portfolio Manager at Satellite Asset Management, LLC from 2005 to 2007 and as an Equity Research Analyst at SAC Capital Management, LLC from 2003 to 2005 and at Merrill Lynch from 1997 to 2002. Mr. Clark began his career at Deloitte & Touche, LLP, progressing to Senior Auditor within its Securities Industry Auditing Group and is a Certified Public Accountant licensed in New York State. He graduated cum laude from the University of Pennsylvania with a Bachelor of Arts in Economics and earned a Masters of Business Administration in Finance and Economics with Distinction (Top 10%) from New York University's Stern School of Business. Mr. Clark's qualifications to serve on the board include his wealth of accounting, financial and investment knowledge and experience in the energy industry provide significant contributions to the Company's board.

Thomas R. Fuller has served as a director since February 2012 and currently serves as Chairman of the Reserves Committee and as a member of the Nominating and Corporate Governance Committee. Mr. Fuller served as a director at Petrohawk Energy Corporation from March 6, 2006 until BHP Billiton acquired Petrohawk in August 2011. Mr. Fuller served on Petrohawk's Reserves Committee and was the Chairman of the Nominating and Corporate Governance Committee. Since December 1988, Mr. Fuller has been a principal of Diverse Energy Management Co. (or related "Diverse" companies), a private upstream acquisition, drilling and production company which also invests in other energy-related companies. Mr. Fuller has earned degrees from the University of Wyoming and the Louisiana State University School of Banking of the South and is a Registered Professional Engineer in Texas. He has 48 years of experience as a petroleum engineer, specializing in economic and reserves evaluation. He has served as an employee, officer, partner or director of various companies, including ExxonMobil, First City National Bank, Hillin Oil Co., Diverse Energy Management Co. and Rimco Royalty Partners. In February 2015, Mr. Fuller became a director of Azure Midstream Partners LP and serves as a member of its Audit Committee. Mr. Fuller also serves as a director of privately held Azure Midstream Holdings. Mr. Fuller also has extensive experience in energy-related merger and acquisition transactions, having generated and closed over 90 producing property acquisitions during his career. As a primary lending officer to many independent energy companies, Mr. Fuller has extensive experience in analyzing and evaluating financial, business and operational strategies for energy companies. Mr. Fuller's qualifications to serve on the board include decades of petroleum engineering, energy-related acquisitions and analytical experience and experience in energy company reserve evaluations provide significant contributions to the Company's board.

Darryl L. Schall has served as a director since the Reorganization in September 2016 and currently serves as a member of the Nominating and Corporate Governance Committee. Mr. Schall is currently an advisor to Ares Management LLC. Mr. Schall previously served as a Partner and Portfolio Manager in the Ares Private Equity Group, where he was responsible for managing Ares' special situations strategy until his retirement in January 2017. Prior to joining Ares in 2009, Mr. Schall worked at Tudor Investment Corporation, where he focused on managing distressed and high yield investments. Previously, Mr. Schall was a Managing Director and Director of High Yield Research at Trust Company of the West, where he focused on managing portfolios of distressed and high yield debt. In addition, Mr. Schall was a Senior Research Analyst and Senior Vice President at Dabney/Resnick & Wagner, Inc., a boutique investment firm specializing in high yield and distressed debt. Previously, Mr. Schall was an Investment Banking Associate of the Corporate Finance Department of Drexel Burnham Lambert Inc. and was a Supervising Senior Accountant with KPMG Peat Marwick. Mr. Schall holds a B.A., cum laude, from the University of California, Los Angeles, in History and an M.B.A. from the University of Chicago. Mr. Schall also is a Certified Public Accountant. Mr. Schall's qualifications to serve on the board include his vast experience managing investment portfolios and extensive knowledge financial and accounting matters provide valuable contributions to the Company's board.

Ronald D. Scott has served as a director since the Reorganization in September 2016 and currently serves as a member of the Reserves Committee. Mr. Scott has over thirty years oil and gas industry experience. Most recently, from 2013 to 2016, Mr. Scott served as President and CEO of True Oil Company, a private equity backed oil and gas firm. Prior to that, from 1996 to 2012, he served as President and Chief Operating Officer of Midland, Texas-based Henry Petroleum and its successor companies, Henry Resources and HPC Energy. During this time, Mr. Scott successfully led the sale and re-start of multiple companies. Beginning his career with Exxon Corporation, from 1983 to 1995, Mr. Scott held various supervisory and managerial assignments in Engineering, Operations, Planning and Financial Accounting and Reporting. In addition to the Permian Basin, he had assignments covering operational areas in the Gulf Coast/Gulf of Mexico region, California and the Rocky Mountains. Mr. Scott was the Technical Manager for Exxon's multi-billion dollar onshore operations in the Western United States and prior to joining Henry Petroleum. Mr. Scott serves as a Director of Blackbrush Oil and Gas and Pardus Oil and Gas and as the Vice President of the Board of the Henry Foundation, a founding member of Educate Midland and on the Chamber of Commerce. Mr. Scott holds Master and Bachelor of Science degrees in Engineering from New Mexico State University and is a Registered Petroleum Engineer in the State of Texas. Mr. Scott's qualifications to serve on the board include his more than thirty years in the oil and gas industry, leadership experience and technical expertise as a petroleum engineer provide significant contributions to the Company's board.

Eric G. Takaha has served as a director since the Reorganization in September 2016 and currently serves as a member of the Audit Committee. Prior to his retirement in 2016, Mr. Takaha served as a Portfolio Manager, Senior Vice President and Director of the Corporate and High Yield Group at Franklin Templeton Investments. He also served as a member of the firm's Fixed Income Policy Committee, which helped guide investment strategies for multi-sector fixed income accounts. At Franklin Templeton Investments, Mr. Takaha managed multiple fixed income portfolios, with a focus on those with corporate credit investments, as well as overseeing and directing the firm's group of high yield and investment grade credit analysts as they formulated investment recommendations. He originally joined Franklin Templeton Investments in 1989, and served as a research analyst covering a number of different industries. Mr. Takaha currently serves as Treasurer and on the Board of the Redwood City Educational Foundation, on the Finance Committee for Make A Wish (San Francisco), on the Investment Sub-Committee for Catholic Charities (San Francisco) and as a mentor in the Friends for Youth organization. He received his B.S. from the University of California Berkeley in 1989 and his M.B.A from Stanford University in 1996. Mr. Takaha is a Chartered Financial Analyst (CFA) Charterholder since 1993 and serves as a member of the CFA Society of San Francisco, the CFA Institute and the Standard Business School Alumni Association. Mr. Takaha's qualifications to serve on the board include his extensive experience overseeing investment strategies, expertise in financial matters and knowledge of financial markets provide valuable contributions to the Company's board.

Nathan W. Walton has served as a director since the Reorganization in September 2016 and currently serves on the Reserves Committee. Mr. Walton is a Partner in the Ares Private Equity Group and joined the firm in 2006. Additionally, he serves on the Investment Committee for Ares EIF funds. Mr. Walton has experience managing investments in, and serving on the Boards of Directors of, companies operating in various industries, including in the oil and natural gas exploration and production industry. Currently, Mr. Walton serves on the Boards of Directors of Clayton Williams Energy, Inc. and the parent company of BlackBrush Oil & Gas, L.P. Mr. Walton holds a B.A. from Princeton University in Politics and an M.B.A. from the Stanford Graduate School of Business. Mr. Walton's qualifications to serve on the board include vast knowledge of the oil and natural gas exploration and production industry, his directorship experience and investment expertise in the energy industry provide significant contributions to the Company's board.

Meetings of Our Board of Directors and Committees of the Board

Our board of directors has the responsibility for establishing our broad corporate policies and for our overall performance. However, the board is not involved in our day-to-day operations. The board is kept informed of our business through discussions with our Chairman and Chief Executive Officer and other officers, by reviewing analyses and reports provided to it on a regular basis, and by participating in board and committee meetings. Our board held 11 meetings during 2016, including telephonic meetings, and acted by unanimous written consent 7 times, and all directors attended at least 75% of the total meetings of the board and the committees on which such director served during the fiscal year.

Our board currently has four standing committees: Audit, Compensation, Nominating and Corporate Governance, and Reserves. Actions taken by our committees are reported to the full board. Each committee conducts an annual evaluation of its duties and is expected to conduct an annual review of its charter. Each committee has authority to retain, set the compensation for, and terminate consultants, outside counsel and other advisers as that committee determines to be appropriate.

Audit Committee. The members of our Audit Committee are James W. Christmas, Michael L. Clark and Eric G. Takaha, with Mr. Christmas serving as the chairman. Our board has determined that all members of our Audit Committee are financially literate within the meaning of SEC rules, under the current listing standards of the NYSE and in accordance with our audit committee charter. Our board has also determined that all members of the Audit Committee are independent, within the meaning of SEC and NYSE regulations for independence for audit committee members, under our corporate governance guidelines, and in accordance with our audit committee charter. The board has also determined that each member of the Audit Committee is an "audit committee financial expert" (as defined under SEC rules) because each possesses: (i) an understanding of generally accepted accounting principles in the United States of America and financial statements; (ii) the ability to assess the general application of such principles in connection with the accounting for estimates, accruals and reserves; (iii) experience analyzing and evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by our financial statements; (iv) an understanding of internal control over financial reporting; and (v) an understanding of audit committee functions. Each of Messrs. Christmas, Clark and Takaha has acquired these attributes by his educational background and by having held various positions that provided relevant experience, as described in his biographical information under "*The Board of Directors*" above.

The Audit Committee is responsible for oversight of Company risks relating to accounting matters, financial reporting and related legal and regulatory compliance. The Audit Committee annually considers the qualifications and evaluates the performance of our independent auditor and selects and engages our independent auditor. The Audit Committee meets quarterly with representatives of the independent auditor and is available to meet at the request of the independent auditor. During these meetings, the Audit Committee receives reports regarding our books of accounts, accounting procedures, financial statements, audit policies and procedures, internal accounting and financial controls, and other matters within the scope of the Audit Committee's duties. The Audit Committee reviews the plans for and the results of audits for us and our subsidiaries. The Audit Committee reviews the independence of the independent auditor, and considers and authorizes the fees for both audit and non-audit services provided by the independent auditor. In 2016, our Audit Committee held 4 meetings.

Compensation Committee. The members of our Compensation Committee are William J. Campbell, James W. Christmas and Michael L. Clark, with Mr. Campbell serving as the chairman. Our board has determined that each member of the Compensation Committee meets the NYSE standards for independence, and is a "non-employee director" as defined in Rule 16b-3 under the Exchange Act, an "outside director" as defined for purposes of Section 162(m) of the Internal Revenue Code of 1986, as amended, and the enhanced independence requirements set forth in Rule 10C-1 under the Exchange Act.

The Compensation Committee is entrusted with the overall responsibility for establishing, implementing and monitoring the compensation for our executive officers (our chief executive officer and president, each executive vice president, and each senior vice president). The Compensation Committee also administers our 2016 Long-Term Incentive Plan, or Plan, and approves restricted stock, stock option, and performance awards and other stock-based grants for our executive officers. In 2016, our Compensation Committee held 6 meetings, including telephonic meetings and acted by unanimous written consent one time.

Our Compensation Committee engaged Longnecker & Associates, Inc. ("Longnecker"), an outside independent compensation consulting firm, to assist the board and the Compensation Committee in crafting our total compensation program for our executive officers for 2016 and to assist the board in determining compensation for our non-employee directors. In connection with its engagement, Longnecker was tasked with, among other things, making recommendations to the Compensation Committee regarding an appropriate compensation peer group, assisting the Compensation Committee in establishing a competitive executive compensation program and making recommendations and providing analysis regarding the compensation of our executive officers, including the named executive officers, discussed below under the heading "*Executive Compensation*."

Nominating and Corporate Governance Committee. The members of our Nominating and Corporate Governance Committee are William J. Campbell, Michael L. Clark, Thomas R. Fuller and Darryl L. Schall, with Mr. Clark serving as the chairman. Our board has determined that all members of the Nominating and Corporate Governance Committee are independent pursuant to the NYSE rules, under our corporate governance guidelines, and in accordance with our nominating and corporate governance committee charter.

Our Nominating and Corporate Governance Committee is responsible for identifying qualified candidates to be presented to our board of directors for nomination as directors, ensuring that our board of directors and our organizational documents are structured in a way that best serves our practices and objectives, and developing and recommending a set of corporate governance principles. The Nominating and Corporate Governance Committee may consider candidates for our board of directors from any reasonable source, including a search firm engaged by the Nominating and Corporate Governance Committee, recommendations of the board of directors, management or, in accordance with the procedures set forth in our bylaws, our stockholders. In 2016, our Nominating and Corporate Governance Committee held 4 meetings, including telephonic meetings and acted by unanimous written consent 3 times.

Reserves Committee. The members of our Reserves Committee are Thomas R. Fuller, Ronald D. Scott and Nathan W. Walton, with Mr. Fuller serving as the chairman. Our Reserves Committee is composed solely of non-employee directors who are independent under our corporate governance guidelines and in accordance with our reserves committee charter. Our Reserves Committee assists our board with oversight in the preparation by independent petroleum engineers of annual and any special reserve reports and/or audits of the estimated amounts of our consolidated hydrocarbon reserves and related information. The Reserves Committee selects, engages and determines funding for the independent petroleum engineers who evaluate our hydrocarbon reserves and also determines their independence from the Company in accordance with, among other things, the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. In 2016, our Reserves Committee held 5 meetings, including telephonic meetings.

Corporate Governance Matters

Corporate Governance Web Page and Available Documents. We maintain a corporate governance page on our website at *www.halconresources.com* where you can find the following documents:

- our corporate governance guidelines;
- our code of ethics;
- our code of conduct;
- our insider trading policy and guidelines with respect to certain transactions in Company securities; and
- the charters of our Audit, Compensation, Nominating and Corporate Governance, and Reserves Committees.

Notwithstanding any reference to our website contained in this report, the information you may find on our website is not part of this report. We will also provide a printed copy of these documents, without charge, to stockholders who request copies in writing from Quentin R. Hicks, Senior Vice President, Finance & Investor Relations, Halcón Resources Corporation, 1000 Louisiana St., Suite 6700, Houston, Texas 77002.

Nomination Process. The Nominating and Corporate Governance Committee will consider stockholder nominees for election as directors. Any stockholder nominations must be received by us not less than sixty (60) days nor more than ninety (90) days prior to the annual meeting; provided however, that in the event that less than seventy (70) days notice or prior public disclosure of the date of the meeting is given or made to stockholders, notice by the stockholder, to be timely, must be received no later than the close of business on the tenth (10th) day following the day on which such notice of the date of the meeting was mailed or such public disclosure was made, whichever first occurs. Nominations should be delivered to the Nominating and Corporate Governance Committee at the following address: Halcón Resources Corporation Nominating and Corporate Governance Committee, c/o Halcón Resources Corporation, Attention: Corporate Secretary, 1000 Louisiana St., Suite 6700, Houston, Texas 77002. The stockholder's nomination notice must set forth: (i) as to each person whom the stockholder proposes to nominate for election or re-election as a director: (a) the name, age, business address and residence address of the person; (b) the principal occupation or employment and business experience of the person for at least the previous five years; (c) the class and number of shares of our capital stock which are beneficially owned by the person; and (d) any other information relating to the person that is required to be disclosed in solicitations for proxies for election of directors pursuant to the rules and regulations of the SEC under Section 14 of the Exchange Act; and (ii) as to the stockholder giving the notice: (a) the name and record address of the stockholder; and (b) the class and number of shares of our capital stock beneficially owned by the stockholder. Such submission must be accompanied by the written consent of the proposed nominee to be named as a nominee and to serve as a director, if elected. We may require any proposed nominee to furnish such other information as may reasonably be required by us to determine the eligibility of such proposed nominee to serve as a director.

In considering possible candidates for election as a director, the Nominating and Corporate Governance Committee is guided by the principles that each director should be an individual of high character and integrity and have:

- independence;
- wisdom;
- an understanding and general acceptance of our corporate philosophies;
- business or professional knowledge and experience that can address our challenges and opportunities, and contribute meaningfully to the deliberations of our board of directors;
- a proven record of accomplishment with an excellent organization;
- an inquiring mind;
- a willingness to speak one's mind;
- an ability to challenge and stimulate management; and
- a willingness to commit time and energy to our business affairs.

In addition to considering possible candidates for election as directors, the Nominating and Corporate Governance Committee may, in its discretion, review the qualifications and backgrounds of existing directors and other nominees (without regard to whether a nominee has been recommended by stockholders), as well as the overall composition of our board, and recommend the slate of directors to be nominated for election at the ensuing annual meeting of stockholders. Currently, we do not employ or pay a fee to any third party to identify or evaluate, or assist in identifying or evaluating, potential director nominees.

The charter of our Nominating and Corporate Governance Committee provides that the Committee will evaluate our corporate governance effectiveness and recommend such revisions as it deems appropriate to improve our corporate governance. The areas of evaluation may include such matters as the size and independence requirements of our board of directors, board committees, management succession and planning, and regular meetings of our non-employee directors without management in executive sessions.

Board Diversity. Our board does not have a formal written policy with regard to the consideration of diversity in identifying director nominees. Our Nominating and Corporate Governance Committee charter, however, requires the committee to review the composition of the board as a whole and recommend, if necessary, measures to be taken so that our board not only contains the required number of independent directors, but also reflects the balance of knowledge, experience, skills, expertise, integrity, analytical ability and diversity as a whole that the committee deems appropriate. This review includes an assessment as to our board's current and anticipated need for directors with specific qualities, skills, experience or backgrounds; the availability of highly qualified candidates; committee workloads and membership needs; and anticipated director retirements.

Leadership Structure. Our board currently combines the role of Chairman with the role of Chief Executive Officer, or CEO, and maintains a separate empowered lead independent director position ("Lead Director") to further strengthen our governance structure. Our board believes this provides an efficient and effective leadership model for the Company. Combining the Chairman and CEO roles fosters clear accountability, effective decision-making and alignment on corporate strategy while reducing the potential for fractured leadership that can undermine successful implementation of policy.

Our board believes that the Company is strengthened by the chairmanship of Mr. Wilson, who provides strategic, operational and technical expertise, vision and a proven ability to lead the Company. Our board believes that, under present circumstances, the interests of the Company and its stockholders are best served by the leadership and direction of Mr. Wilson as Chairman, CEO and President. Our board recognizes that no single leadership model is right for all companies and at all times and that, depending on the circumstances, other leadership models, such as a separate independent chairman of the board, might be appropriate.

Mr. James W. Christmas, who is an independent and non-management director, has served as our Lead Director since January 21, 2015. A Lead Director is elected annually by our board and serves as a key component of our governance structure, subject to oversight by the independent members of our board. The Lead Director's responsibilities and authority generally include:

- presiding over all executive sessions of the independent directors and all other board meetings at which the Chairman is not present;
- calling special meetings of the independent directors when necessary and appropriate;
- coordinating the agenda for, and moderating sessions of, the board's independent directors;
- serving as a liaison between the Chairman and the independent directors;
- consulting with the Chairman regarding specific agenda items and additional materials for board meetings suggested by independent board members;
- approving the scheduling of regular and, where feasible, special meetings of the board to ensure that there is sufficient time for discussion of all agenda items;
- facilitating communications among the other members of the board;
- consulting with the chairs of the board committees and soliciting their participation to avoid diluting their authority or responsibilities; and
- performing other duties as the board may from time to time delegate.

Our corporate governance guidelines currently provide that non-management directors must meet at regularly scheduled executive sessions without management. Mr. Christmas, as Lead Director, presided over the executive sessions of our non-management directors during 2016. During 2016, our non-management directors held 4 executive sessions without management present, and Mr. Christmas presided over each executive session.

Risk Oversight. It is the job of our CEO and President, Chief Financial Officer, Chief Legal Officer, and other members of our senior management to identify, assess, and manage our exposure to risk. In conjunction with our risk oversight program, senior management has retained outside consultants to assist in identifying, assessing, analyzing and developing plans to mitigate enterprise risks. Our board plays an important role in overseeing management's performance of these functions. Our board has approved the charter of its Audit Committee, which lists the primary responsibilities of the Audit Committee. Those responsibilities require the Audit Committee to discuss with management our major financial risk exposures and the steps management has taken to monitor and control such exposures, including the substance of any significant litigation, contingencies or claims that had, or may have, a significant impact on the financial statements. The Audit Committee is also required to discuss with management and review the mechanisms, guidelines and policies that govern the processes by which risk assessment and management are undertaken.

Each of the board's other committees also oversees the management of risks that fall within such committee's area of responsibility. Our Compensation Committee incorporates risk considerations, including the risk of loss of key personnel, as it evaluates the performance of our CEO and President and other executive officers, reviews management development and determines compensation structure and amounts. Our Nominating and Corporate Governance Committee focuses on issues and risks relating to board composition, leadership structures, succession planning and corporate governance matters. The focus of our Reserves Committee is on the integrity of the process of selecting our independent petroleum engineers and whether reports prepared by our independent petroleum engineers are prepared in accordance with the accepted or required petroleum engineering standards.

Our board receives reports from its committees regarding the risks considered in their respective areas to ensure that our board has a broad view of our strategy and overall risk management process. In performing its risk oversight function, each committee has full access to management, as well as the ability to engage advisors. Each committee's charter is available on our website at *www.halconresources.com*.

Communications with Directors. Our board welcomes communications from our stockholders and other interested parties. Stockholders and any other interested parties may send communications to our board, to any committee of our board, to the Lead Director, or to any director in particular to: c/o Halcón Resources Corporation, Attention: Corporate Secretary, 1000 Louisiana St., Suite 6700, Houston, Texas 77002. Any correspondence addressed to our board, to any committee of our board, to the Lead Director, or to any one of the directors in care of our offices is required to be forwarded to the addressee or addressees without review by any person to whom such correspondence is not addressed.

Directors' Attendance at Stockholder Meetings. Our corporate governance guidelines provide that our directors are encouraged, but not required, to attend annual meetings of our stockholders.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires our directors, executive officers and persons who beneficially own more than 10% of our common stock to file certain reports with the SEC concerning their beneficial ownership of our equity securities. The SEC's regulations also require that a copy of all such Section 16(a) forms filed must be furnished to us by the executive officers, directors and greater than 10% stockholders. To our knowledge based solely on a review of copies of reports filed under Section 16(a) during the 2016 fiscal year and furnished to us, our directors, executive officers and holders of 10% or more of our shares timely filed reports required by Section 16(a).

Code of Conduct and Code of Ethics

The Company's Code of Conduct and Code of Ethics for the Chief Executive Officer and Senior Financial Officers can be found on the Company's website located at *www.halconresources.com*. Any stockholder may request a printed copy of such materials by submitting a written request to the Company's Corporate Secretary. If the Company amends the Code of Ethics or grants a waiver, including an implicit waiver, from the Code of Ethics, the Company will disclose the information on its website. The waiver information will remain on the website for at least twelve months after the initial disclosure of such waiver.

Management

The following table sets forth the names and ages of all of our executive officers, the positions and offices with us currently held by such persons and the months and years in which continuous service began:

Name	Executive Officer Since	Age	Position
Floyd C. Wilson	Feb. 2012	70	Chairman of the Board, Chief Executive Officer and President
Stephen W. Herod	May 2012	57	Executive Vice President, Corporate Development
Mark J. Mize	Feb. 2012	45	Executive Vice President, Chief Financial Officer and Treasurer
David S. Elkouri	May 2012	63	Executive Vice President and Chief Legal Officer
Jon C. Wright	May 2012	47	Executive Vice President, Operations
Quentin R. Hicks	Aug. 2013	42	Senior Vice President, Finance and Investor Relations
Leah R. Kasparek	May 2012	47	Senior Vice President, Human Resources and Administration
Tina S. Obut	Feb. 2013	52	Senior Vice President, Corporate Reserves
Joseph S. Rinando, III	May 2012	45	Senior Vice President, Chief Accounting Officer and Controller

Our executive officers are appointed to serve until the meeting of the board of directors following the next annual meeting of stockholders and until their successors have been elected and qualified. The following paragraphs contain certain information about each of our executive officers other than Mr. Wilson, whose biographical information is included under the heading "*The Board of Directors*" above.

Stephen W. Herod has served as our Executive Vice President, Corporate Development since September 9, 2016, having previously served as our President from May 2012. Mr. Herod served as Executive Vice President—Corporate Development and Assistant Secretary of Petrohawk Energy Corporation from August 2005 until BHP Billiton acquired Petrohawk in August 2011. Mr. Herod served as Vice President—Corporate Development of Petrohawk from May 2004 until August 2005. Prior to joining Petrohawk, he was employed by PHAWK, LLC from its formation in June 2003 until May 2004. He served as Executive Vice President—Corporate Development for 3TEC Energy Corporation from December 1999 until its merger with Plains Exploration & Production Company in June 2003 and as Assistant Secretary from May 2001 until June 2003. Mr. Herod served as a director of 3TEC from July 1997 until January 2002. Mr. Herod served as the Treasurer of 3TEC from 1999 until 2001. From July 1997 to December 1999, Mr. Herod was Vice President—Corporate Development of 3TEC. Mr. Herod served as President and a director of Shore Oil Company from April 1992 until the merger of Shore with 3TEC's predecessor in June 1997. He joined Shore's predecessor as Controller in February 1991. Mr. Herod was employed by Conquest Exploration Company from 1984 until 1991 in various financial management positions, including Operations Accounting Manager. From 1981 to 1984, Superior Oil Company employed Mr. Herod as a financial analyst. Mr. Herod has a Bachelor of Science degree in finance and management from Oklahoma State University.

Mark J. Mize has served as Executive Vice President, Chief Financial Officer and Treasurer since February 2012. Mr. Mize served as Executive Vice President—Chief Financial Officer and Treasurer of Petrohawk Energy Corporation from August 2007 until BHP Billiton acquired Petrohawk in August 2011. Mr. Mize served as the Chief Ethics Officer and Insider Trading Compliance Officer for Petrohawk until June 2009. Additionally, he served as Vice President, Chief Accounting Officer and Controller at Petrohawk from July 2005 until August 2007. Mr. Mize first joined Petrohawk in

November 2004 as Controller. Prior to working at Petrohawk, Mr. Mize was the Manager of Financial Reporting of Cabot Oil & Gas Corporation, a public oil and gas exploration company, from January 2003 to November 2004. Prior to his employment at Cabot Oil & Gas Corporation, he was an Audit Manager with PricewaterhouseCoopers LLP from 1996 to 2002. Mr. Mize is a Certified Public Accountant and has a Bachelor degree in Accounting from the University of Houston.

David S. Elkouri has served as Executive Vice President and Chief Legal Officer since April 2014. Mr. Elkouri served as Executive Vice President, General Counsel from May 2012 to April 2014. Mr. Elkouri served as Executive Vice President—General Counsel and Secretary of Petrohawk Energy Corporation from 2007 until BHP Billiton acquired Petrohawk in August 2011. He also served as Chief Ethics Officer and Insider Trading Compliance Officer of Petrohawk. From 2004 to 2007, he served as lead outside counsel for Petrohawk. Prior to that, Mr. Elkouri served as lead outside counsel for 3TEC Energy Corporation from 1999 to 2003. He also served as lead outside counsel for Hugoton Energy Corporation from 1994 to 1998. Mr. Elkouri is a co-founder of Hinkle Law Firm LLC where he practiced for 20 years prior to joining Petrohawk. Mr. Elkouri is a graduate of the University of Kansas School of Law where he served as a Research Editor of the Kansas Law Review.

Jon C. Wright has served as Executive Vice President, Operations since September 2016. Mr. Wright served as Senior Vice President, Operations from December 2014 to September 2016 and as Vice President, Operations from May 2012 to December 2014. Mr. Wright served as W. Rockies Operations Manager at Newfield Exploration from 2009 until 2012. Mr. Wright also served as Lead, Production for W. Oklahoma and Lead Drilling for Woodford Shale from 2005 until 2009. Prior to that, Mr. Wright was a Senior Drilling Engineer at BP from 2004 to 2005. He also served as Drilling Engineer from 2001 to 2004. From 1997 to 2001, he held various drilling positions for Conoco. Mr. Wright has a Bachelor of Science degree in Petroleum Engineering from Texas A&M University and a Master of Business Administration degree from Rice University.

Quentin R. Hicks has served as Senior Vice President, Finance and Investor Relations since January 2016. Mr. Hicks served as Vice President, Finance from August 2013 to January 2016. Mr. Hicks initially joined Halcón as Director of Financial Planning in August 2012 after GeoResources merged with Halcón. While with GeoResources, Mr. Hicks served as Director of Acquisitions and Financial Planning from 2011 to 2012. From 2004 to 2011, he worked in investment banking with Bear Stearns, Sanders Morris Harris and most recently Madison Williams, where he was a Director in their energy investment banking practice. Prior to that, Mr. Hicks worked as Manager of Financial Reporting for Continental Airlines. He began his career in 1998 working as an auditor for Ernst and Young LLP. Mr. Hicks graduated from Texas A&M University with a Bachelor of Business Administration and a Master of Science degree in accounting. In addition, he holds a Masters of Business Administration degree in finance from Vanderbilt University. Mr. Hicks is a Certified Public Accountant.

Leah R. Kasparek has served as Senior Vice President, Human Resources and Administration since December 2014. Ms. Kasparek served as Vice President, Human Resources from May 2012 to December 2014. Ms. Kasparek initially joined Halcón as Director of Human Resources in February 2012. Prior to joining Halcón, Ms. Kasparek held numerous HR leadership positions across multiple industries including oil and gas, utilities and manufacturing. Ms. Kasparek served as Director of Human Resources at Southwestern Energy from 2009 to January 2012. She served as Vice President of Human Resources for CenterPoint Energy from 2004 until 2008. From 1996 to 2004, Ms. Kasparek was employed by Anheuser-Busch Companies and served as Vice President of Human Resources from 2001 until 2004. Ms. Kasparek has a Bachelor of Arts degree from the University of Southwestern Louisiana and a law degree from the University of Houston Law Center.

Tina S. Obut has served as Senior Vice President, Corporate Reserves since December 2014. Ms. Obut served as Vice President, Corporate Reserves from February 2013 to December 2014. Ms. Obut served as Senior Manager of Petroleum Resources at BHP Billiton Petroleum from 2011 to 2012. Prior to that, she served as Senior Vice President, Corporate Reserves for Petrohawk Energy Corporation from 2006 until its sale to BHP Billiton in 2011. From 2004 to 2006, Ms. Obut served as Manager of Reservoir Engineering Evaluations at El Paso Production Company. In addition, she held various engineering, managerial and executive positions at Mission Resources, Ryder Scott Company and Chevron from 1989 to 2006. Ms. Obut has a Bachelor of Science degree in Petroleum Engineering from Marietta College, a Master of Science degree in Petroleum and Natural Gas Engineering from Penn State and a Master of Business Administration degree from the University of Houston. Ms. Obut is a Licensed Professional Engineer in the State of Texas (#82050).

Joseph S. Rinando, III has served as Senior Vice President, Chief Accounting Officer and Controller since December 2014. Mr. Rinando served as Vice President and Chief Accounting Officer from May 2012 to December 2014. Mr. Rinando initially joined Halcón as Director of Finance in February 2012. Mr. Rinando served as Vice President and Chief Financial Officer of Wilson Industries, a Schlumberger company, from 2010 to 2012. Prior to joining Wilson, he served as Executive Vice President and Chief Financial Officer for Foxxe Energy Services, LLC, a private-equity owned international drilling rig contractor, from 2009 to 2010. Prior to Foxxe, Mr. Rinando served as Vice President and Corporate Controller of Smith International, Inc. from 2006 until 2009 and as Director of Financial Reporting from 2003 to 2006. From 1995 to 2003, he was in the Energy Practice of PricewaterhouseCoopers, LLP, most recently as an Audit Senior Manager, serving clients focused on exploration and production, natural gas transmission, power and utilities, petrochemicals and refining, and drilling. Mr. Rinando graduated Summa Cum Laude with a Bachelor of Business Administration degree in Accounting from Lamar University and is a Certified Public Accountant in the State of Texas.

ITEM 11. EXECUTIVE COMPENSATION

The following discussion of executive compensation contains descriptions of various employment-related agreements and employee benefit plans. These descriptions are qualified in their entirety by reference to the full text of the referenced agreements and plans, which have been filed by us as exhibits to our reports on Forms 10-K, 10-K/A, 10-Q and 8-K filed with the SEC.

Our Compensation Policies and Process

Our Compensation Committee

Our compensation programs for senior management are overseen by the Compensation Committee of our board. The Compensation Committee is composed entirely of independent directors. Until the Reorganization Plan Effective Date, our Compensation Committee consisted of Michael A. Vlasic (Chairman), Tucker S. Bridwell, Daniel A. Rioux and Mark A. Welsh IV. From and after the Reorganization Plan Effective Date, our Compensation Committee consisted of William J. Campbell (Chairman), James W. Christmas and Michael L. Clark.

The Compensation Committee operates pursuant to delegated authority from our board as specified in the Compensation Committee's Charter. The primary duties and responsibilities of the Compensation Committee pursuant to its charter are to establish and implement our compensation policies and programs for senior management, including the named executive officers. The Compensation Committee has the authority to select and engage the services of a compensation consultant, independent legal counsel and such other advisors as the Compensation Committee determines appropriate to carry out its functions, and has the sole authority to engage, obtain the advice of, oversee, terminate and determine funding for such independent professional advisers. A copy of the Compensation Committee charter is available on our website at *www.halconresources.com* under the section entitled "*Investor Relations—Corporate Governance*." The Compensation Committee also reviews and assesses the adequacy of its charter, at least annually, and recommends any proposed changes to our board for approval.

The Chairman of the Compensation Committee works with certain members of our management, including our Senior Vice President, Human Resources and Administration, to establish an agenda for each meeting of the Compensation Committee and, with the assistance of outside advisors, to prepare meeting materials. Typically our Chief Executive Officer and President, and our Senior Vice President, Human Resources and Administration, as well as outside advisors, may be invited to attend all or a portion of a Compensation Committee meeting depending on the nature of the matters to be discussed. Only members of the Compensation Committee vote on items before the Compensation Committee; however, the Compensation Committee and board often solicit the views of senior management on compensation matters, in particular as they relate to the compensation of other members of senior management.

Our Compensation Philosophy and Program Design

Our success depends on the continued contributions of our senior management and other key employees. Our compensation program is intended to recruit, motivate and retain the talent required to successfully manage and grow our business and to achieve our short and long-term business strategy by providing compensation that is competitive in relation to our peers while fostering an atmosphere of teamwork, recognizing overall business results and individual merit, and supporting the attainment of our strategic objectives by tying the interests of senior management and key employees to those of our stockholders. The design of our compensation program is intended to provide compensation that balances short-term and long-term goals through the use of annual cash incentives and grants of long-term equity incentives; and provides a mix of fixed and at-risk compensation that is related to our overall performance and the creation of stockholder value.

Each element of compensation is reviewed and considered with the other elements of compensation to ensure that it is consistent with the objectives of both that particular element of compensation and our overall compensation program and, that individually and collectively, our compensation practices do not encourage inappropriate, unnecessary or excessive risk taking.

Our Independent Compensation Consultant

For 2016, the Compensation Committee engaged Longnecker to advise on executive compensation and, in that capacity to, among other things, make recommendations regarding an appropriate compensation peer group, to assist the Compensation Committee in establishing a competitive executive compensation program and to make recommendations and provide analysis regarding the compensation of senior management. In accordance with the rules of the NYSE, the Compensation Committee annually considers the independence of Longnecker from Company management based upon various factors, including the magnitude of any fees the consultant received from the Company for services or products provided to the Company relative to the firm's annual gross revenues; whether the individuals that advise the Compensation Committee participate directly or by collaboration with others in the firm in the provision of any services or products to the Company; whether the consultant provided any products or services to any executive officer of the Company; and whether the individuals that advise the Compensation Committee own any Company securities. After considering these various factors, the Compensation Committee determined that Longnecker was independent of Company management during the relevant periods covered by this report. No conflicts of interest or issues involving the independence of Longnecker arose during the periods covered by this report.

Representatives of Longnecker report directly to the Compensation Committee and, in carrying out its duties, may work with our Senior Vice President, Human Resources and Administration when preparing materials for the Compensation Committee. Longnecker attends Compensation Committee meetings, meets with the Compensation Committee independently without the presence of management and provides third-party data, analysis, advice and expertise on executive compensation and executive compensation programs. Longnecker generates reports that include a compilation of compensation data based upon our compensation peer group and particularized data for industry participants to the extent Longnecker determined that such additional data would prove useful in our compensation process. Additionally, at the direction of the Compensation Committee, Longnecker also reviews materials prepared by certain members of senior management and advises the Compensation Committee on the matters included in the materials, including the consistency of management proposals with the Committee's compensation philosophy, programs and objectives and the degree to which such proposals conformed with compensation peer group data and peer company practices. The Company relied upon this data, Longneckers' analyses of the data and its recommendations in establishing our compensation peer group, compensation programs and in establishing specific compensation amounts for our senior management, including the named executive officers. Longnecker also advises the Compensation Committee regarding terms of employment agreements negotiated with senior management.

Our Compensation Peer Group

We review the compensation and benefit practices, as well as levels of pay, of a compensation peer group of companies selected by the Compensation Committee, with the advice and assistance of Longnecker, from U.S. onshore focused oil and natural gas exploration and development companies when considering our compensation program and the compensation that we pay senior management. With Longnecker's assistance, we annually review, evaluate and update our compensation peer group for benchmarking purposes to provide ongoing comparability for compensation purposes. Adjustments to our compensation peer group are made due to business combinations or sales of peer group companies, as well as when necessary, in the opinion of our Compensation Committee, to better reflect the companies that compete with us for management talent and share common characteristics with our business, including assets, production levels, revenues, oil and natural gas reserves and production mix, market capitalization and enterprise value.

Our compensation peer group for 2016 consisted of the following ten companies:

- SandRidge Energy, Inc.
- Bonanza Creek Energy, Inc.
- Resolute Energy Corporation
- Newfield Exploration Co.
- Oasis Petroleum Inc.
- Sanchez Energy Corporation
- Stone Energy Corporation
- Northern Oil and Gas, Inc.
- Gulfport Energy Corporation
- Magnum Hunter Resources Corporation

Elements of Compensation

The principal elements of our executive compensation program are base salary, annual cash incentives, long-term equity incentives and post-termination severance (under certain circumstances), and other benefits and perquisites, consisting of life and health insurance benefits, a qualified 401(k) savings plan, the reimbursement of certain club dues for our Chief Executive Officer and President and our Chief Financial Officer and limited tax gross ups for life insurance, parking and country club memberships. As discussed below, in March 2016, we also paid one-time retention bonuses to senior management to retain their services through the Reorganization.

Currently, we target total compensation at approximately the 50th percentile of our compensation peer group but may change targets from time to time depending on various factors, including the competitive environment for talent and the recommendations of the Compensation Committee's independent compensation consultant. Also, from time to time, the Compensation Committee will vary the mix of compensation utilized, depending upon our Compensation Committee's current view of the most efficacious method to provide incentives under current market conditions, taking into account the compensation practices of our compensation peer group and the advice of our independent compensation consultant.

With respect to annual cash incentives, our Compensation Committee typically establishes performance metrics near the beginning of each year that it utilizes as a guideline in conjunction with its determination of annual cash incentives (i.e., cash bonuses) for senior management following year-end, which may include measures relating to leverage and liquidity, operational efficiency and financial performance. As a general matter, these measures of performance collectively aggregate approximately 50% of the overall weighting that factors into annual cash incentive determinations and 50% is based on other factors the Compensation Committee deems relevant and appropriate, including individual performance. However, regardless of the relative weighting of these factors, the actual amount of any annual cash incentive award is entirely discretionary. Our Compensation Committee believes retaining discretion over the amount of such awards is necessary in light of the dynamic nature of the Company's activities, the potential for rapid changes in the business environment and the limitations inherent in quantitative measures of performance.

Impacts of Our Reorganization on Compensation

Some aspects of the compensation of the Company's executives during 2016 were directly related to market conditions and the Company's financial position at the time. The compensation necessary to retain the management team during this time period was deliberate in order to ensure the Company had the appropriate resources to review and make appropriate strategic decisions about the reorganization and work through the reorganization in a strategic way that optimized the best results for a viable entity following emergence from chapter 11 bankruptcy. Certain aspects of the compensation structure during 2016 was of a non-recurring nature.

On March 9, 2016, the Company announced it had engaged PJT Partners as financial advisor and Weil, Gotshal & Manges, LLP as legal advisor to assist the Company in exploring opportunities to materially reduce its indebtedness while preserving liquidity. The retention of our management team while the Company considered possible scenarios to improve its balance sheet and capital structure, was critical to the potential long-term success and viability of the Company. Accordingly in March 2016, the Predecessor Compensation Committee recommended and the Predecessor board subsequently approved, a key employee retention program ("KERP") pursuant to which the Company made a one-time cash retention payment to certain executive officers and key employees. The KERP was implemented with the objective of incentivizing such executive officers and key employees to continue employment with the Company during this period of uncertainty. The KERP was formulated with the input and based on the recommendations of Longnecker, after consultation with the Company's external advisors, PJT Partners and Weil, Gotshal & Manges, LLP. Pursuant to the KERP, key employees receiving retention payments entered into a key employee retention agreement with the Company pursuant to which they agreed to continue their employment with the Company for a period of no less than twelve months from the date thereof or they will forfeit, and be required to repay, the full amount of the retention payment they receive (less any taxes withheld), provided that their employment is not terminated prior to such date by the Company without cause or by them with good reason, such as due to a material reduction in base salary or permanent relocation of their principal place of employment.

Pursuant to the terms of the Reorganization Plan, any restricted shares of common stock issued pursuant to the Halcón Resources Corporation First Amended and Restated 2012 Long-Term Incentive Plan were vested immediately prior to the Reorganization Plan Effective Date and all outstanding awards of performance shares and options were cancelled. Upon the Reorganization Plan Effective

Date, all outstanding common stock was cancelled and the holders thereof received a pro rata amount of 4% of our newly issued shares of common stock. The other 96% of our common stock issued upon our emergence went to our creditors in accordance with the Reorganization Plan. As a consequence, our senior management's equity in the reorganized company, along with all of our other pre-emergence common stockholders, was diluted substantially. The terms of the Reorganization Plan provided for 10% of our newly issued shares of common stock to be reserved for issuance as awards under a management incentive plan. On the Reorganization Plan Effective Date, the Halcón Resources Corporation 2016 Long-Term Incentive Plan was approved and adopted by our existing board and exit awards allocated as determined by the CEO were awarded in the form of restricted common stock and stock options. The awards are intended to align the interests of our key executives with those of our equity holders by providing a significant equity interest in the Company, conditioning certain equity awards upon continued employment with us and providing an "at-risk" component of compensation linked directly to increases in shareholder value.

Each of the elements of our compensation program is discussed in greater detail below.

Base Salary

We review base salaries for our senior management annually to determine if any modification is appropriate. We consider several factors, including a comparison to base salaries paid for comparable positions in our compensation peer group, the relationship among base salaries paid within our Company and individual experience and contributions. Our intent is to fix base salaries at levels that we believe are consistent with our compensation program design objectives.

For 2016, in light of the current market conditions and the pending hiring of advisors to consider reorganization, the prior Compensation Committee determined to leave base salaries for the named executive officers unchanged from 2015.

Annual Cash Incentives

Annual cash incentives for senior management are typically reviewed following the end of the year. Our Compensation Committee awarded annual cash incentives to Mr. Wilson, Mr. Herod and Mr. Mize in the amounts of $275,000, $165,000 and $146,667, respectively, which amounts reflected prorated awards for the period following the Reorganization Plan Effective Date through year-end.

Long-term Incentives

Long-term incentives comprise a significant portion of an executive's compensation package. Long-term incentives are consistent with our objective of providing an "at-risk" component of compensation. Providing long-term incentive award opportunities for senior management and key employees align their interests with those of our stockholders. Historically, we have awarded grants of restricted stock, stock options and performance units, to certain members of senior management, including the named executive officers. Each of these awards is discussed in more detail below. Historically, we have utilized this combination because of the differing risk and reward characteristics of these awards. From time to time, we may utilize a different mix of these awards or utilize other forms of awards, each of which is permitted under the Plan and discussed in more detail below, depending upon the Compensation Committee's current view of the most efficacious method to provide incentives under current market conditions and taking into account the practices of our compensation peer group. The amounts granted will vary each year and are based on performance of senior management, our analysis of compensation peer group data and the total compensation package of each member of senior management, as discussed in more detail below.

The long-term incentive information related to the named executive officers during fiscal year 2016 is included in the Summary Compensation Table set forth below. Additional information on long-term incentive awards for 2016 is shown in the Grants of Plan-Based Awards in 2016 table and the Outstanding Equity Awards at December 31, 2016 table, each of which is set forth below. As noted above, our Compensation Committee elected not to award long-term equity incentives to the named executive officers during its annual compensation review held in February 2016; however, as discussed above, exit awards were made upon the Reorganization Plan Effective Date in accordance with the terms of the Reorganization Plan to senior management, including the named executive officers under the 2016 Long-term Incentive Plan. These awards included a mix of restricted stock and stock options, with approximately two-thirds of the award, by dollar value, in the form of stock options having an exercise price equal to the greater of (1) the per share value based on the Company's post-Reorganization equity value of $650.0 million or (2) the weighted average trading price of the newly issued common stock for the seven (7) trading days commencing on the first trading day immediately following the Reorganization Plan Effective Date (assuming the new common shares were then publicly traded) with the vesting period of such stock options being over 3 years in equal annual installments provided the recipient remains employed by the Company as of the respective annual vesting dates and the remaining one-third of the award, by dollar value, in the form of restricted stock granted on the first full day of trading of the new common shares following the Reorganization Plan Effective Date, of which 50% vested in full on the date of grant and the remaining 50% would vest on the first anniversary of the grant, in each case provided the recipient remains employed by the Company as of such vesting date.

2016 Long-Term Incentive Plan

We grant equity awards under our 2016 Long-Term Incentive Plan, which for purposes of this discussion we referred to as the "Plan." The Plan became effective upon the Reorganization Plan Effective Date and originally provided for a total of 10 million shares of common stock.

As of February 28, 2017, a total of 1,733,067 shares of common stock had been granted as restricted stock and were outstanding, 5,313,200 shares were reserved for the exercise of outstanding stock options and 1,703,733 shares of our common stock remained available for issuance pursuant to the Plan. The Plan permits granting awards in a wide variety of forms, including options to purchase our common stock, shares of restricted stock, restricted stock units (granting the recipient the right to receive common stock), shares of incentive stock (common stock issued without a restriction period), stock appreciation rights, performance units (settled in common stock or cash) and performance bonuses (settled in common stock or cash). We currently utilize as awards under the Plan only restricted stock and stock options. No more than 10 million shares of common stock may underlie awards to a single recipient in any calendar year, and performance bonuses may not exceed $5 million to any recipient in any calendar year.

The Plan will expire on September 9, 2026. No grants will be made under the Plan after that date, but all grants made on or prior to such date will continue in effect thereafter subject to the terms of the award and of the Plan. Our board may, in its discretion, terminate the Plan at any time. The termination of the Plan would not affect the rights of participants or their successors under any awards outstanding and not exercised in full on the date of termination. The board may at any time, and from time to time, amend the Plan in whole or in part. Any amendment that must be approved by our stockholders in order to comply with the terms of the Plan, applicable law or the rules of the principal securities exchange, association or quotation system on which our common stock is then traded or quoted will not be effective unless and until such approval has been obtained. The board is not permitted, without the further approval of the stockholders, to make any alteration or amendment that would materially increase the benefits accruing to participants under the Plan, increase the aggregate number of shares that may be issued pursuant to the provisions of the Plan, change the class of individuals eligible to receive awards under the Plan or extend the term of the Plan.

Stock Options

An important objective of our long-term incentive program is to strengthen the relationship between the long-term value of our stock price and the potential financial gain for employees. Stock options provide participants with the opportunity to purchase our common stock at a price fixed on the grant date regardless of future market price. A stock option becomes valuable only if our common stock price increases above the option exercise price and the holder of the option remains employed during the period required for the option to vest, thus providing an incentive for an option holder to remain employed by us. Stock options link the option holder's compensation to stockholders' interests by providing an incentive to increase the market price of our stock.

Option grants to senior management are generally considered annually, typically in February, after our year-end results become available, while grants to other eligible officers and employees are generally considered in December of each year. Our practice is that the exercise price for each stock option is the market value on the date of grant, which is normally the date that our Compensation Committee approves the award at a meeting of the Compensation Committee or a trading day after our release of earnings or other material nonpublic information. Our current policy provides for grants to be made or priced only during a trading window and within such window only at such time as there is no material non-public information regarding the Company. Under the Plan, the stock option price may not be less than the fair market value (the closing market price) of the shares on the date of grant. With respect to employees who are not executive officers, the Compensation Committee typically delegates the authority to make such grants to our chief executive officer but specifies the total number of shares that may be subject to grants and the other material terms of the grants. All proposed stock options to new-hire employees are required to be approved by our Compensation Committee. Alternatively, our Compensation Committee may authorize in writing, in advance of any fiscal quarter, the number of shares underlying stock options that may be granted to new-hire employees for the following fiscal quarter and provide that our chief executive officer may allocate such stock options at his discretion.

Stock options generally vest and become exercisable one-third annually after the original grant date. In certain instances, however, stock options may vest on an accelerated basis, such as in the event an executive's employment is terminated by us without cause or by the executive with good reason, in the event that the executive terminates his or her employment within a certain period following a transaction that effects a change in the control of our Company, or in the event of the executive's death or disability while employed by us. Under these circumstances all stock options held by the executive may automatically vest and become exercisable in accordance with the terms outlined in his or her stock option award agreement or employment agreement, if applicable. The employment agreements that we have entered into with the named executive officers provide for all stock options held by each executive to automatically vest and become exercisable in the event his or her employment is terminated by us without cause, by the executive for good reason or with or without good reason within a two-year period following a change of control of our Company.

There is a limited term in which an executive can exercise stock options, known as the "option term." The option term is generally ten years from the date of grant, which is the maximum term of an option permitted under the Plan. At the end of the option term, the right to purchase shares pursuant to any unexercised option expires.

Information relating to the stock options issued to the named executive officers during 2016 are shown in the table below entitled "*Grants of Plan-Based Awards in 2016*".

Restricted Stock Awards

Restricted stock awards are shares of our common stock that are awarded with the restriction that the executive remain with us through certain "vesting" dates. Prior to the restrictions thereon lapsing, the participant may not sell, transfer, pledge, assign or take any similar action with respect to the shares of restricted stock which the participant owns. Despite the restrictions, each participant will have full voting rights and will receive any dividends or other distributions, if any, with respect to the shares of restricted stock which the participant owns. Once the restrictions lapse with respect to shares of restricted stock, the participant owning such shares will hold freely-transferable shares, subject only to any restrictions on transfer contained in our certificate of incorporation, bylaws and insider trading policies, as well as any applicable federal or state securities laws.

Restricted stock awards provide the opportunity for capital accumulation and more predictable long-term incentive value. The purpose of granting restricted stock awards is to encourage ownership and retention of our senior management and result in business decisions that may drive stock price appreciation. Recognizing that our business is subject to significant fluctuations in commodity prices that may cause the market value of our common stock to fluctuate, we also intended the awards to provide an incentive for senior management to remain with us throughout commodity price and business cycles.

Restricted stock awards generally vest one-third annually after the original award date. As a consequence, the recipients do not become unconditionally entitled to retain any of the shares of restricted stock until one year following the date of grant, subject to certain exceptions related to termination of employment. Any unvested restricted stock awards generally are forfeited if the executive terminates employment with us. In certain instances, however, restricted stock awards may vest on an accelerated basis, such as in the event of the executive's employment is terminated by us without cause or by the executive with good reason, in the event that the executive terminates his or her employment within a certain period following a transaction that effects a change in the control of our Company, or in the event of the executive's death or disability while employed by us. Under these circumstances all restricted stock awards held by the executive may automatically vest in accordance with the terms outlined in the restricted stock award agreement or the employment agreement, if applicable. The employment agreements that we have entered into with the named executive officers provide for all restricted stock awards held by an executive to automatically vest in the event his or her employment is terminated by us without cause, by the executive for good reason or by the executive with or without good reason within a two-year period following a change of control of our Company.

The restricted stock grants to the named executive officers during fiscal year 2016 are shown below in the table entitled "*Grants of Plan-Based Awards in 2016*."

Retirement Benefits

We do not maintain a defined benefit pension plan or retiree medical program that covers members of senior management. Retirement benefits to our senior management, including the named executive officers, are currently provided solely through a tax-qualified profit sharing and 401(k) plan (our "Savings Plan"), in which eligible full-time employees may participate. Pursuant to the Savings Plan, employees may elect to reduce their current annual compensation up to the lesser of 75% or the statutorily prescribed limit of $18,000 in calendar year 2016 (plus up to an additional $6,000 in the form of "catch-up" contributions for participants age 50 and above), and have the amount of any reduction contributed to the Savings Plan. Our Savings Plan is intended to qualify under sections 401(a) and 401(k) of the Internal Revenue Code of 1986, as amended (the "Code"), so that contributions by us or our employees to the Savings Plan and income earned on contributions are not taxable to employees until withdrawn from the Savings Plan and so that contributions will be deductible by us when made. We match 100% of the amount an employee contributes to the Savings Plan, up to a maximum contribution of 10%. Members of senior management participate in the Savings Plan on the same basis as other eligible employees.

The Savings Plan provides for various investment options, for which the participant has sole discretion in determining how both the employer and employee contributions are invested. The independent trustee of the Savings Plan then invests the assets of the Savings Plan as directed by participants. The Savings Plan does not provide our employees the option to invest directly in our securities. The Savings Plan offers in-service withdrawals in the form of after-tax account distributions and age 59.5 distributions.

We believe that the Savings Plan supports the objectives of our compensation structure, including the ability to recruit and retain senior and experienced mid- to late-career executive talent for critical positions within our organization.

Outstanding Equity Awards Under the Plan

The following tables represent outstanding equity awards under the Plan as of December 31, 2016. We do not issue awards under any other plan.

	Number of Securities to be Issued Upon Exercise of Outstanding Options	Weighted-Average Exercise Price of Outstanding Options	Average Remaining Contractual Life (Years)
Stock Options	5,319,400	$9.22	9.7

	Number of Securities to be Issued Upon Vesting
Restricted Stock	1,738,077

As of December 31, 2016 a total of 1,689,398 shares of our common stock were available for future grants under the Plan. As of February 28, 2017, approximately 1,703,733 shares of our common stock are available for future grants under the Plan.

Employment Contracts, Termination of Employment and Change-in-Control Arrangements

During 2012, we entered into employment agreements with each member of our senior management, including Messrs. Wilson, Herod and Mize. Strong competition for management talent and uncertainty associated with our business plan and our stated willingness to embrace consolidation trends in our industry led us to conclude that it was appropriate and in our best interests to enter into employment agreements with each of such named executive officers.

Term of Employment Agreements

The initial term of employment of Mr. Wilson was for a term of two years from June 1, 2012, the effective date of his employment agreement, which the Company elected to renew for an additional two years effective June 1, 2014 and June 1, 2016, respectively. The initial term of employment of each of Messrs. Herod and Mize was originally until December 31, 2013, with automatic one-year extensions unless either party provides written notice thirty days prior to expiration of the initial term or any extension. Our failure to renew an executive's employment agreement will be considered a termination without cause under each employment agreement.

Compensation and Benefits

The salary of each named executive officer is subject to periodic review and may be increased from time to time by the Compensation Committee. Each named executive officer is eligible to receive bonuses, grants of stock options, restricted stock or other equity awards as determined in the discretion of the Compensation Committee. Each of the named executive officers is also entitled to reimbursement for reasonable business expenses and to participate in our life, health, and dental insurance programs, and all other employee benefit plans which we may, from time to time, make available. We provide tax gross-ups on a limited basis for life insurance, parking and country club memberships.

Our Chief Executive Officer and President is entitled under his employment agreement to receive a vehicle allowance and reimbursement for reasonable fees and membership dues for one Houston area country club. Our Chief Financial Officer is entitled under his employment agreement to be reimbursed for reasonable fees and membership dues for one Houston area country club.

Our use of expense reimbursement and perquisites as an element of compensation is limited. We do not view these items as a significant element of our compensation structure but do believe that they can be used in conjunction with base salary to recruit, motivate and retain executive talent in a competitive environment. The Compensation Committee periodically reviews these items provided to determine if they are appropriate and if any adjustments are warranted.

Termination Provisions and Severance Payments

We may terminate each named executive officer's employment upon disability, and at any time for cause or without cause. Each named executive officer may terminate his or her employment at any time, and such termination will be deemed to be with "good reason" if it is based on a material reduction in base salary; a material reduction in authority, responsibilities or duties or those of the supervisor to whom the named executive officer reports; a material reduction in the budget over which the named executive officer retains authority; a permanent relocation of the named executive officer's principal place of employment to any location outside a fifty mile radius of the location from which named executive officer provides services to the Company; or any uncured material breaches of the employment agreement by us. If the employment of any of the named executive officers is terminated by death or disability, such named executive officer (or his or her personal representative in the event of death) is entitled to receive accrued unpaid base compensation, plus an optional bonus to be determined by the Compensation Committee, and all stock options and other incentive awards held by the named executive officer will become fully vested and immediately exercisable, and all restrictions on any shares of restricted stock will be removed. If the employment of any of the named executive officers is terminated by us for cause, such named executive officer (or his or her personal representative in the event of death) is entitled to receive accrued unpaid base compensation.

If the employment of any named executive officer is terminated by us without cause or by such named executive officer with good reason, and such termination is not within two years after a change in control, such named executive officer will be entitled to the accrued portion of unpaid salary, payment of the greater of a prorated amount of the named executive officer's target bonus for the year in which the termination occurs or a bonus for such year as may be determined by our Compensation Committee in its sole discretion, a severance payment equal to one year's base salary plus the higher of the current year target bonus or the bonus paid for the preceding year, payment of the premiums for medical, vision and dental insurance for the executive and his or her dependents for up to one year following termination, and the full vesting of all unvested options and earned performance units (if applicable) and all restrictions removed from shares of restricted stock.

If such named executive officer is terminated by us without cause or such named executive officer terminates his or her employment with the Company *with or without* good reason, and such termination is within two years after a change in control, such named executive officer will be entitled to receive the accrued portion of unpaid salary, payment of the greater of a prorated amount of the named executive officer's target bonus for the year in which the termination occurs or a bonus for such year as may be determined by our Compensation Committee in its sole discretion, a severance payment equal to a multiple (which varies by individual) of base salary plus the higher of the current year target bonus or the bonus paid for the year prior to termination or the year in which the change of control occurred, payment of the premiums for medical, vision and dental insurance for the executive and his or her dependents for up to eighteen months following termination, and the full vesting of all unvested options and earned performance units (if applicable) and all restrictions removed from shares of restricted stock. The multiplier for Mr. Wilson is 3.0, and for Messrs. Herod and Mize it is 2.5. In addition, if a bonus for the named executive officer for the year immediately preceding the termination has been determined but not paid as of the date of termination, the named executive officer will be paid the bonus so determined; and if such a bonus has not been determined, then the named executive officer will be paid a bonus equal to the greater of such named executive officer's target bonus for such year, or for the year in which the termination occurs or the change of control occurs, or the bonus paid to executive for the year immediately preceding the year in which the change of control occurs. If the employment of such named executive officer is terminated by such named executive officer without good reason and not within two years after a change in control, such named executive officer is entitled to receive accrued unpaid base compensation.

The employment agreements with the named executive officers generally define a change of control to mean any of the following events:

- any person or group becomes the "beneficial owner" (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of more than 35% of the total voting power of our outstanding voting stock;
- our merger with or consolidation into another entity and, immediately after giving effect to the merger or consolidation, one or both of the following occurs: (a) less than 50% of the total voting power of the outstanding voting stock of the surviving or resulting entity is then "beneficially owned" in the aggregate by our stockholders immediately prior to such merger or consolidation, or (b) the individuals who were members of our board of directors immediately prior to the execution of the agreement providing for the merger or consolidation do not constitute at least a majority of the members of the board of directors of the surviving or resulting entity;
- we sell, assign, convey, transfer, lease or otherwise dispose of all or substantially all of our assets to a third party in one transaction or a series of related transactions;
- individuals who constitute our board of directors cease for any reason to constitute at least a majority of our board of directors unless such persons were elected, appointed or nominated by a vote of at least a majority of our incumbent directors; or
- the complete liquidation or dissolution of our Company.

In our view, having the change of control and severance protections helps to maintain the named executive officer's objectivity in decision-making and provides another vehicle to align the interests of our named executive officers with the interests of our stockholders.

The following table sets forth the estimated amounts that would be payable to each of the named executive officers upon a termination under the scenarios outlined above, excluding termination for cause or on account of death or disability, assuming that such termination occurred on December 31, 2016 and using the closing price of our common stock at December 31, 2016 for purposes of the calculations as required by the SEC. The dollar amounts set forth under the column heading "*Early Vesting of Restricted Stock/Options/PSUs*" correspond to the amounts that would be paid, in addition to accrued and unpaid salary through the date of death or disability, in the event of the death or disability at year-end of each of the executives. There can be no assurance that these scenarios would produce the same or similar results as those disclosed if a termination occurs in the future.

	Severance Payment[(1)]	Early Vesting of Restricted Stock/ Options/PSUs[(2)]	Other[(3)]	Total
Without Cause/For Good Reason				
Floyd C. Wilson	$1,500,000	$4,535,188	$34,314	$6,069,502
Stephen W. Herod	$ 900,000	$1,187,063	$34,314	$2,121,377
Mark J. Mize	$ 800,000	$1,187,063	$34,314	$2,021,377
Following Change of Control				
Floyd C. Wilson	$4,500,000	$4,535,188	$51,471	$9,086,659
Stephen W. Herod	$2,250,000	$1,187,063	$51,471	$3,488,534
Mark J. Mize	$2,000,000	$1,187,063	$51,471	$3,238,534

(1) Represents total annual cash compensation (2016 base salary plus target bonus, which is 100% of base salary for each officer, in accordance with the terms of the employment agreement), which, in the event of a change of control, has been multiplied by the applicable multiplier set forth in each officer's employment agreement.

(2) The value of unvested restricted stock and stock options that would vest under each termination scenario is based on the closing price of our common stock on December 31, 2016.

(3) Represents an estimate of health insurance benefits to be provided to the named executive officer and each eligible dependent under each of the scenarios based on actual amounts paid out in 2016.

Board Representation

Mr. Wilson's employment agreement provides that he will be nominated as a member of our board, and that we will use our best efforts to cause him to be elected, appointed, or re-elected or re-appointed, as a director.

Indemnity Agreements

We have entered into an indemnity agreement with each of our non-employee directors and Messrs. Wilson and Mize. These agreements provide for us to, among other things, indemnify such persons against certain liabilities that may arise by reason of their status or service as directors or officers, to advance their expenses incurred as a result of a proceeding as to which they may be indemnified and to cover such person under any directors' and officers' liability insurance policy we choose, in our discretion, to maintain. These indemnity agreements are intended to provide indemnification rights to the fullest extent permitted under applicable indemnification rights statutes in the State of Delaware and are in addition to any other rights such person may have under our certificate of incorporation, bylaws and applicable law. We believe these indemnity agreements enhance our ability to recruit and retain knowledgeable and experienced executives and independent, non-management directors.

Tax Deductibility

Section 162(m) of the Code limits the deductibility of compensation in excess of $1 million paid to our chief executive officer and our three next most highly compensated executive officers (other than our principal financial officer) unless the compensation is performance-based as determined by applying certain specific and detailed criteria. We believe that it is often desirable and in our best interests to deduct compensation payable to our executive officers. However, we also believe that there are circumstances where our interests are best served by maintaining flexibility in the way compensation is provided, even if it might result in the non-deductibility of certain compensation under the Code. In this regard, we consider the anticipated tax treatment to our Company and our executive officers in the review and establishment of compensation programs and payments; however, we may pay compensation to our executives that may not be deductible, including discretionary bonuses or other types of compensation outside of our plans.

Summary Compensation Table

The table below sets forth information regarding compensation for our named executive officers for the years indicated (commencing with the first year in which such officer became one of our named executive officers):

Name and Principal Position	Year	Salary(1)	Bonus(2)	Stock Awards(3)	Option/SAR Awards(3)	All Other Compensation(4)	Total
Floyd C. Wilson	2016	$750,000	$3,275,000	$8,604,750	$11,463,436	$31,510	$24,124,696
Chairman of the Board, Chief Executive Officer and President	2015	$750,000	—	$1,040,495	$ 1,120,732	$27,450	$ 2,938,677
	2014	$750,000	$ 322,500	$2,058,065	—	$27,461	$ 3,158,026
Stephen W. Herod	2016	$450,000	$ 965,000	$2,252,250	$ 3,000,497	$31,510	$ 6,699,257
Executive Vice President, Corporate Development	2015	$450,000	—	$ 378,742	$ 407,949	$26,909	$ 1,263,600
	2014	$450,000	$ 193,500	$1,140,473	—	$25,975	$ 1,809,948
Mark J. Mize	2016	$400,000	$ 946,667	$2,252,250	$ 3,000,497	$38,461	$ 6,637,875
Executive Vice President, Chief Financial Officer and Treasurer	2015	$400,000	—	$ 375,502	$ 404,461	$34,824	$ 1,214,787
	2014	$400,000	$ 172,000	$ 997,882	—	$31,266	$ 1,601,148

(1) *Represents actual base salary paid in the year.*

(2) *Comprised of a retention bonus paid prior to the Company and its subsidiaries filing of voluntary petitions under chapter 11 of the bankruptcy code and an annual cash incentive bonus paid subsequent to year end for prior year performance.*

(3) *Represents the grant date fair value of awards granted during the indicated year, as determined in accordance with ASC Topic 718. Pursuant to SEC rules, the amounts shown exclude the impact of estimated forfeitures related to service-based vesting conditions. Please see the discussion of the assumptions made in the valuation of these awards in "Note 13—Stockholders' Equity" to the audited consolidated financial statements included in our annual report on Form 10-K for the year ended December 31, 2016. See "Grants of Plan-Based Awards in 2016" for information on awards made in 2016. Generally, the full grant date fair value is the amount that we would expense in our financial statements over the award's vesting schedule. These amounts reflect our accounting expense, and do not correspond to the actual value that will be recognized by the named executive officers.*

(4) *For 2016, the amounts reported for "All Other Compensation" include amounts provided to the named executive officers as outlined in the table below, with respect to (a) the matching contribution that we make on account of employee contributions under our 401(k) Savings Plan, (b) premiums paid by the Company for executive long-term disability insurance, (c) tax gross-ups for life insurance and parking payments and (d) country club membership paid by the Company for Mr. Mize.*

	All Other Compensation ($)			
	(a)	(b)	(c)	(d)
Named Executive Officer				
Floyd C. Wilson	24,000	1,593	5,917	—
Stephen W. Herod	24,000	1,593	5,917	—
Mark J. Mize	18,000	1,593	5,917	12,951

Grants of Plan-Based Awards in 2016

The table below sets forth information regarding grants of plan-based awards made to our named executive officers during 2016.

Name	Grant Date		Estimated Future Payouts Under Equity Incentive Plan Awards[1] Target(#)		Type of Award[2]	Exercise or Base Price of Option Awards ($/Sh)[3]	Grant Date Fair Value of Stock and Option Awards[4]
Floyd C. Wilson	9/12/2016	—	1,862,500	—	Options	$9.24	$11,463,436
	9/12/2016	—	931,250	—	Restricted Stock		$ 8,604,750
Stephen W. Herod	9/12/2016	—	487,500	—	Options	$9.24	$ 3,000,497
	9/12/2016	—	243,750	—	Restricted Stock		$ 2,252,250
Mark J. Mize	9/12/2016	—	487,500	—	Options	$9.24	$ 3,000,497
	9/12/2016	—	243,750	—	Restricted Stock		$ 2,252,250

(1) *Awards granted under the Plan provide only for a single estimated payout. Under the Plan there are no minimum amounts payable for a certain level of performance and there are no maximum payouts possible above the target. Thus, there are no thresholds or maximums (or equivalent items) applicable to these awards.*

(2) *Represents shares of restricted stock and stock options issued under the Plan. The shares of restricted stock vest in two equal installments, half on the date of grant and half on the first anniversary of the date of grant, provided that the recipient has been continuously employed at such date. Stock options vest in three equal installments on each anniversary of the date of grant, beginning on the first anniversary of the date of grant, in each case, provided that the recipient has been continuously employed at such date.*

(3) *The exercise price of each award is equal to the weighted average closing market price of our common stock for seven trading days following the date of grant.*

(4) *Represents the full grant date fair value determined in accordance with ASC Topic 718. Please see the discussion of the assumptions made in the valuation of these awards in "Note 13—Stockholders' Equity" to the audited consolidated financial statements included in our annual report on Form 10-K for the year ended December 31, 2016. Generally, the full grant date fair value is the amount that we would expense in our financial statements over the award's vesting schedule. These amounts reflect our*

accounting expense, and do not correspond to the actual value that will be recognized by the named executive officers.

Outstanding Equity Awards at December 31, 2016

The following table summarizes the number of securities underlying outstanding plan awards for each named executive officer as of December 31, 2016.

	Option Awards				Stock Awards			
Name	Number of Securities Underlying Unexercised Options Exercisable	Number of Securities Underlying Unexercised Options Unexercisable(1)	Option Exercise Price	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested(1)	Market Value of Shares or Units of Stock That Have Not Vested(2)	Equity Incentive Plan Awards: Number of Unearned Shares, Units Or Other Rights That Have Not Vested	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested
Floyd C. Wilson . .	—	1,862,500	$9.24	9/12/2026	465,625	$4,348,938	—	$—
Stephen W. Herod	—	487,500	$9.24	9/12/2026	121,875	$1,138,313	—	$—
Mark J. Mize	—	487,500	$9.24	9/12/2026	121,875	$1,138,313	—	$—

(1) *The shares of restricted stock vest in two equal installments, half on the date of grant and half on the first anniversary of the date of grant, provided that the recipient has been continuously employed at such date. Stock options vest in three equal installments on each anniversary of the date of grant, beginning on the first anniversary of the date of grant, in each case, provided that the recipient has been continuously employed at such date.*

(2) *Calculated based upon the closing market price of our common stock as of December 30, 2016, the last trading day of our 2016 fiscal year ($9.34) multiplied by the number of unvested awards at year end.*

Compensation Adjustments Subsequent to Fiscal Year End

Subsequent to December 31, 2016, the compensation committee awarded the following increase in base salary in response to competitive compensation practices.

Name	Base Salary Increase
Floyd C. Wilson	$50,000

Option Exercises and Stock Vested

The following table summarizes option exercises and the vesting of restricted stock for our named executive officers in 2016.

	Option Awards		Stock Awards	
Name	Number of Shares Acquired on Exercise	Value Realized on Exercise[(1)]	Number of Shares Acquired on Vesting	Value Realized on Vesting[(2)]
Floyd C. Wilson	—	—	723,210	$5,143,616
Stephen W. Herod	—	—	234,508	$1,363,193
Mark J. Mize	—	—	224,905	$1,359,774

(1) *The value realized upon the exercise of the option award is determined by multiplying the number of shares acquired on exercise by the difference between the closing price of our common stock on the date of exercise and the exercise price of the option.*

(2) *The value realized equals the closing price of our common stock on the date of vesting, multiplied by the number of shares vested.*

Stock Ownership Guidelines Policy

Our board of directors has adopted an Amended and Restated Stock Ownership Guidelines Policy (the "Policy") applicable to our board of directors, chief executive officer and president and each executive vice president to ensure that they maintain a meaningful economic stake in the Company. The Policy is designed to maintain stock ownership of our directors and the specified officers at a significant level so as to further align their interests with the interests of our stockholders in value creation. Subject to certain exceptions contained in the Policy, our directors are required to hold a number of shares of our common stock valued at three times (3x) the annual cash retainer paid to them by the Company, our chief executive officer and president is required to hold a number of shares of our common stock valued at six times (6x) the base salary paid to him by the Company and the other specified officers are required to hold a number of shares of our common stock valued at three times (3x) the base salaries paid to them by the Company. For purposes of calculating the value of shares owned, each share of stock shall have a deemed value equal to the greater of the price at acquisition or the current market value. For purposes of calculating the value of unvested restricted shares, the value shall be determined without giving effect to the restriction.

DIRECTOR COMPENSATION

The table below sets forth certain information concerning the compensation earned in 2016 by our non-employee directors for service on our board of directors and committees of the board of directors during 2016.

Name	Fees Earned or Paid in Cash	Stock Awards(1)(2)	Option Awards	All Other Compensation	Total(3)
William J. Campbell	$ 28,001	$135,004	$—	$—	$163,005
James W. Christmas	$227,715	$135,004	$—	$—	$362,719
Michael L. Clark	$ 29,556	$135,004	$—	$—	$164,560
Thomas R. Fuller	$176,276	$135,004	$—	$—	$311,280
Darryl L. Schall	$ 23,334	$135,004	$—	$—	$158,338
Ronald D. Scott	$ 23,334	$135,004	$—	$—	$158,338
Eric G. Takaha.	$ 24,111	$135,004	$—	$—	$159,115
Nathan W. Walton	$ 23,334	$135,004	$—	$—	$158,338

(1) Represents the grant date fair value of awards granted during the indicated year, as determined in accordance with ASC Topic 718. Pursuant to SEC rules, the amounts shown exclude the impact of estimated forfeitures related to service-based vesting conditions. Please see the discussion of the assumptions made in the valuation of these awards in "Note 13—Stockholders' Equity" to the audited consolidated financial statements included in our annual report on Form 10-K for the year ended December 31, 2016. Generally, the full grant date fair value is the amount that we would expense in our financial statements over the award's vesting schedule. These amounts reflect our accounting expense, and do not correspond to the actual value that will be recognized by our directors.

(2) The number of restricted stock awards subject to vesting, excluding shares received in lieu of fees, made to each of our directors for service as a director during 2016 was 17,264.

(3) Represents the numerical sum of the dollar amounts reflected in each other column for each director.

Discussion of Director Compensation Table

Employee directors receive no additional compensation for service on our board of directors or any committee of the board of directors. All directors receive actual expense reimbursements associated with attending board and committee meetings. Our director compensation program has been developed with the advice and guidance of our independent compensation consultant using peer group and market data and consists of two principal elements: (1) annual retainer and committee fees and (2) equity consisting of restricted stock awards. Our Compensation Committee reviews our director compensation program at least annually, and more frequently if circumstances warrant it, using the advice and information provided by our independent compensation consultant. Our non-employee directors received an award of restricted stock under our 2016 Plan with value of $135,004; they will receive annually an award of restricted stock under our 2016 Plan having a value of $165,000, which grant shall be made following our annual meeting of stockholders. Our non-employee directors also receive an annual cash retainer of $70,000, payable on a quarterly basis and pro rated for actual service during the year. Our lead independent director receives an additional $25,000 per year, also payable on a quarterly basis and pro rated for actual service during the year. Additional annual compensation for each committee chairperson and committee member for all of the committees of our board of directors is set forth below:

Board Committee	Committee Chairperson Additional Compensation	Committee Member (excluding Chairperson) Additional Compensation
Audit	$25,000	$7,500
Compensation	$15,000	$5,000
Nominating and Corporate Governance	$12,500	$5,000
Reserves	$12,500	$5,000

Fees are paid in four equal quarterly installments and board members may elect to take all or a portion of the cash compensation we pay to them in shares of our common stock, with the number of shares determined by dividing such fees by the trading price per share of our common stock on the last day of each calendar quarter. Any such election must be made prior to the beginning of the quarter for which the compensation is to be paid and is irrevocable for that quarter.

COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

No member of the Compensation Committee during 2016 served as one of our officers or employees or of any of our subsidiaries during that year. In addition, during 2016, none of our executive officers served as a director or as a member of the compensation committee of a company which employs any of our directors.

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

Security Ownership of Certain Beneficial Owners and Management

The following sets forth information regarding the beneficial ownership of our common stock as of February 28, 2017 by:

- each person to be known by us to be the beneficial owner of more than 5% of our outstanding shares of common stock;
- each of our named executive officers;
- each of our directors; and
- all of our current executive officers and directors as a group.

As of February 28, 2017, approximately 93 million shares of our common stock were outstanding. Unless otherwise noted, the mailing address of each person or entity named below is 1000 Louisiana St., Suite 6700, Houston, Texas 77002.

Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class(1)
Franklin Resources, Inc.(2)	34,261,424	36.7%
Ares Management LLC(3)	18,357,256	19.7%
Tyrus Capital S.A.M.(4)	9,126,652	9.7%
Floyd C. Wilson(5)	1,160,149	1.2%
Stephen W. Herod(6)	275,353	*
Mark J. Mize(7)	269,553	*
William J Campbell(8)	17,264	*
James W. Christmas(9)	53,340	*
Michael L. Clark(10)	17,264	*
Thomas R. Fuller(11)	27,685	*
Darryl L. Schall(12)	—	*
Ronald D. Scott(13)	17,264	*
Eric G. Takaha(14)	17,264	*
Nathan W. Walton(15)	—	*
All directors and executive officers as a group (13 individuals)	2,616,147	2.8%

* *Less than 1%.*

(1) *Unless otherwise indicated, each stockholder has sole voting and investment power with respect to all shares of common stock indicated as being beneficially owned by such stockholder. Shares of common stock that are not outstanding, but which a designated stockholder has the right to acquire within 60 days, are included in the number of shares beneficially owned by such stockholder and are deemed to be outstanding for purposes of determining the percentage of outstanding shares beneficially owned by such stockholder, but not for purposes of determining the percentage of outstanding shares beneficially owned by any other designated stockholder. In all instances where ownership of unvested restricted stock is reported below, the individual has the sole power to vote such shares but no investment power.*

(2) *According to, and based solely upon, Schedule 13G/A filed by Franklin Resources, Inc., Charles B. Johnson, Rupert H. Johnson, Jr. and Franklin Advisers, Inc. (collectively, "Franklin") with the SEC on February 5, 2016. The business address for Franklin is One Franklin Parkway, San Mateo, CA 94403.*

(3) *The business address of Ares Management LLC is 2000 Avenue of the Stars, 12th Floor, Los Angeles, CA 90067.*

(4) *According to, and based solely upon, Schedule 13G/A filed by Tyrus Capital S.A.M.. and Tony Chendraoui (collectively, "Tyrus") with the SEC on February 14, 2017. The business address for Tyrus is 4 Avenue Roqueville, Monaco, MC 98000.*

(5) *Includes 465,625 shares of unvested restricted stock. Also includes 7,019 shares held in seventeen trusts for the benefit of Mr. Wilson's children and grandchildren, of which Mr. Wilson is the trustee and disclaims beneficial ownership of such shares. Does not include 6,583 shares held in three trusts for the benefit of Mr. Wilson's children, of which Mr. Wilson's wife is the trustee and he disclaims beneficial ownership of such shares.*

(6) Includes 121,875 shares of unvested restricted stock. Does not include 2,749 shares held in trusts for the benefit of Mr. Herod's minor children, of which Mr. Herod disclaims beneficial ownership of such shares and has no dispositive or voting power with respect to the shares held by such trusts.

(7) Includes 121,875 shares of unvested restricted stock. 1,964 shares held by Mr. Mize are pledged.

(8) The business address for Mr. Campbell is 820 Gessner, Suite 1460, Houston, TX 77024.

(9) Does not include 177 shares of common stock held in three trusts for his children. Mr. Christmas has no dispositive or voting power with respect to the shares held by such trusts. The business address for Mr. Christmas is c/o Halcón Resources Corporation, 1000 Louisiana Street, Suite 6700, Houston, TX 77002.

(10) The business address for Mr. Clark is c/o Halcón Resources Corporation, 1000 Louisiana Street, Suite 6700, Houston, TX 77002.

(11) The business address for Mr. Fuller is 19500 SH 249, Suite 640, Houston, TX 77070.

(12) The business address for Mr. Schall is c/o Halcón Resources Corporation, 1000 Louisiana Street, Suite 6700, Houston, TX 77002.

(13) The business address for Mr. Scott is 1030 Andrews Highway, Suite 200, Midland, TX 79703.

(14) The business address for Mr. Takaha is c/o Halcón Resources Corporation, 1000 Louisiana Street, Suite 6700, Houston, TX 77002.

(15) The business address for Mr. Walton is 2000 Avenue of the Stars, 12th Floor, Los Angeles, CA 90067.

Equity Compensation Plan Information

The following table sets forth certain information as of December 31, 2016 with respect to compensation plans (including individual compensation arrangements) under which our equity securities are authorized for issuance.

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options and Rights(a)	Weighted-Average Exercise Price of Outstanding Options and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column(a))
Equity compensation plans approved by security holders(1)	7,057,477(2)	$9.22	1,689,398
Equity compensation plans not approved by security holders	—	—	—
	7,057,477(2)	$9.22	1,689,398

(1) Represents information for the 2016 Long-Term Incentive Plan.

(2) Includes 1,738,077 shares of restricted stock not yet vested.

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

Charter of Aircraft. In the ordinary course of its business, the Company occasionally charters private aircraft from unaffiliated air charter companies. Floyd C. Wilson, the Company's Chairman, CEO and President, indirectly owns an aircraft which is managed by an independent air charter company unaffiliated with both Mr. Wilson and the Company. The Company occasionally charters private aircraft, including the aircraft owned indirectly by Mr. Wilson, from this company. The aircraft in the air charter company's fleet, including the aircraft indirectly owned by Mr. Wilson, are available to the public for charter based upon a standard fee schedule established by the air charter company, with the fees dependent primarily upon the type and size of the aircraft utilized and the duration of the flight. During 2016, the Company paid a total of approximately $0.5 million to the air charter company that manages Mr. Wilson's aircraft, all of which was related to the use of the aircraft indirectly owned by Mr. Wilson. Because the air charter company establishes fees for the use of the aircraft in its fleet, Mr. Wilson does not receive any greater benefit from the Company's charter of the aircraft indirectly owned by him than he does if any third party were to charter those aircraft. Any fees related to the charter of the aircraft are paid to the air charter company, which deducts from revenues received from charter customers a variety of expenses incidental to use of the aircraft (such as personnel, fuel and commissions) and recurring charges (such as for inspections, maintenance, storage and service).

The use of charter and Company-owned aircraft by Company personnel is governed by the Company's Aircraft Policy. Our policies do not require that a special committee of the Company's independent directors approve the use of aircraft chartered through an unaffiliated air charter company that independently establishes the amount charged under arrangements that otherwise comply with our Aircraft Policy.

Related Party Transaction Review Policies and Procedures. A transaction or series of similar transactions to which we are a party in which the amount involved exceeds $120,000 and involves a director, executive officer, 5% stockholder or any immediate family members of these persons is evaluated by a special committee of disinterested directors formed by our board of directors to evaluate such transactions. In addition, our code of conduct provides that every employee should disclose any material transaction or relationship that could reasonably be expected to give rise to a conflict of interest to upper management or the Company's Audit Committee. The Audit Committee has the authority to evaluate any such conflicts of interest and recommend actions to be taken by our board in connection with such conflicts of interest or to report the existence of any such conflicts of interest to the full board for it to take action.

Director Independence. The current listing standards of the NYSE require our board to affirmatively determine the independence of each director and to disclose such determination in the proxy statement for each annual meeting of our stockholders. The board, on February 28, 2017, affirmatively determined that each of Messrs. Campbell, Christmas, Clark, Fuller, Schall, Scott, Takaha and Walton is an "independent director" under the guidelines described below and the independence rules of the NYSE codified in Section 303A of the NYSE Listed Company Manual.

In connection with its assessment of independence, our board reviewed information regarding relevant relationships, arrangements or transactions between the Company and each director or parties affiliated with such director. Our board has established the following standards for determining director independence in our corporate governance guidelines:

A majority of the directors on our board must be "independent." No director qualifies as "independent" unless the board affirmatively determines that the director has no "material relationship" with the Company, either directly, or as a partner, shareholder or officer of an organization that has a relationship with the Company. A "material relationship" is a relationship that the board determines, after a consideration of all relevant facts and circumstances, compromises the director's independence from management. Our board's determination of independence must be consistent with all applicable requirements of the NYSE, the SEC, and any other applicable legal requirements. Our board may adopt specific standards or guidelines for independence in its discretion from time to time, consistent with those requirements. As set forth in the NYSE Listed Company

Manual Section 303A.02, our board must consider the following factors that preclude a finding by the board of a member's or prospective member's "independence" from the Company:

1. A director who is, or who has been within the last three years, an employee of the Company (including in each case subsidiaries or parent entities in a consolidated group), or an immediate family member who is, or has been within the last three years, an executive officer, of the Company;

2. A director who has received, or has an immediate family member who has received, during any twelve-month period within the last three years, more than $120,000 in direct compensation from the Company, other than director and committee fees and pension or other forms of deferred compensation for prior service (provided such compensation is not contingent in any way on continued service); provided, that, compensation received by a director for former service as an interim Chairman or CEO or other executive officer need not be considered in determining independence under this test, and compensation received by an immediate family member for service as an employee of the Company need not be considered in determining independence under this test;

3. (A) A director is a current partner or employee of a firm that is the Company's internal or external auditor; (B) a director who has an immediate family member who is a current partner of such a firm; (C) a director who has an immediate family member who is a current employee of such a firm and who participates in the Company's audit; or (D) a director or an immediate family member who was within the last three years (but is no longer) a partner or employee of such a firm and personally worked on the Company's audit within that time;

4. A director or an immediate family member who is, or who has been within the last three years, employed as an executive officer of another company where any of the Company's present executive officers at the same time serves or served on that company's compensation committee;

5. A director who is a current employee, or an immediate family member who is a current executive officer, of a company that has made payments to, or received payments from, the Company for property or services in an amount which, in any of the last three fiscal years, exceeds the greater of $200,000, or 2% of such other company's consolidated gross revenues;

6. Whether the director has any other relationship with the Company, either directly or as a partner, shareholder or officer of an organization that has a relationship with the Company; and

7. Whether the director is aware of any other relationships that could potentially interfere, or could appear to interfere, with his exercise of independent judgment in carrying out the responsibilities of a director, including (i) any transaction, arrangement or relationship, in the last fiscal year, involving the director, including any family members, and any other officer or director of the Company; or (ii) any other relationship with the Company, either directly or as a shareholder, executive officer or partner or an organization that has such a relationship, including any relationships with charitable, educational, political or other not-for-profit organizations.

For purposes of determining "independence" of a director based on the tests set forth above, among other things, the following applies:

A. In applying the test in paragraph 5 above, both the payments and the consolidated gross revenues to be measured are those reported in the last completed fiscal year. The look-back provision for this test applies solely to the financial relationship between the Company and the director or immediate family member's current employer; the Company is not required to consider former employment of the director or the immediate family member.

B. For purposes of paragraph 5 above, contributions to tax exempt organizations are not considered "payments," although the Company still considers the "materiality" of any such relationship in determining the "independence" of a director.

C. For purposes of determining "independence," an "immediate family member" includes a person's spouse, parents, children, siblings, mothers and fathers-in-law, sons and daughters-in-law, brothers and sisters-in-law, and anyone (other than a domestic employee) who shares such person's home, and does not include individuals who are no longer immediate family members as a result of legal separation or divorce, or those who have died or become incapacitated.

Our corporate governance guidelines set forth our policy with respect to qualifications of the members of the board, the standards of director independence, director responsibilities, board meetings, director access to management and independent advisors, director orientation and continuing education, director compensation, Chairman and CEO dual responsibilities, management evaluation and succession, annual performance evaluation of the board, and executive sessions.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Principal Accountant

Deloitte is the independent registered public accounting firm selected by our Audit Committee as the independent registered public accountant for the fiscal years ended December 31, 2016 and 2015. During the years ended December 31, 2016 and 2015, neither the Company nor anyone acting on its behalf consulted Deloitte with respect to the application of accounting principles to a specified transaction, either completed or proposed, or the type of audit opinion that might be rendered on the Company's consolidated financial statements, or any other matters or reportable events as defined in Items 304(a)(1)(iv) and (v) of Regulation S-K.

Fees

The following table presents fees billed for professional audit services rendered by Deloitte, our principal accounting firm for the years ended December 31, 2016 and 2015. The table also presents fees for other services rendered by Deloitte during those periods. Except as set forth below, we paid all such fees.

	2016	2015
Audit Fees	$1,679,469	$1,604,908
Audit-Related Fees	203,013	100,000
Tax Fees	2,654,768	—
All Other Fees	—	—
Total	$4,537,250	$1,704,908

As used above, the following terms have the meanings set forth below:

Audit Fees. The fees for professional services rendered by Deloitte for the audit of our annual financial statements, for the review of the financial statements included in our quarterly reports on Form 10-Q and for services that are normally provided by the accountants in connection with statutory and regulatory filings or engagements and private placements, including but not limited to registration statements, for the years ended December 31, 2016 and 2015.

Audit-Related Fees. The fees for assurance and related services by Deloitte that are for audit, valuation services related to the Reorganization and valuation services for a specific subsidiary that are reasonably related to the performance of the audit or review of our financial statements and are not otherwise reported under "Audit Fees."

Tax Fees. The fees for professional services rendered by Deloitte for tax compliance, tax advice, and tax planning.

All Other Fees. The fees for products and services provided by Deloitte, other than for the services reported under the headings "Audit Fees," "Audit-Related Fees" and "Tax Fees," for the period in question.

Audit Committee Pre-Approval Policy

All audit fees, audit-related fees and tax fees as described above for the years ended December 31, 2016 and 2015 were pre-approved by our Audit Committee, which concluded that the provision of such services by Deloitte was compatible with the maintenance of their respective independence in the conduct of their auditing functions. Our Audit Committee's pre-approval policy provides that pre-approval of all such services must be approved separately by the Audit Committee. The Audit Committee has not delegated any such pre-approval authority to anyone outside the Audit Committee. Each member of the Audit Committee has the authority to pre-approve non-audit services up to $200,000 to be performed by our independent registered public accountant.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(1) Consolidated Financial Statements:

The consolidated financial statements of the Company and its subsidiaries and reports of independent registered public accounting firms listed in Section 8 of this Annual Report on Form 10-K are filed as a part of this Annual Report on Form 10-K.

(2) Consolidated Financial Statements Schedules:

All schedules are omitted because they are inapplicable or because the required information is contained in the financial statements or included in the notes thereto.

(3) Exhibits:

2.1	Order of the Bankruptcy Court, dated September 8, 2016, confirming the Amended Joint Prepackaged Plan of Reorganization of Halcón Resources Corporation, et al, under Chapter 11 of the Bankruptcy Code, together with such Amended Joint Prepackaged Plan of Reorganization (Incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed September 9, 2016).
2.2*	Purchase and Sale Agreement dated January 18, 2017, by and between Halcón Energy Properties, Inc. and Samson Exploration, LLC.
2.3*	Agreement of Sale and Purchase dated January 24, 2017, by and among Halcón Energy Properties, Inc., Halcón Holdings, Inc., HK Energy, LLC, HK Oil & Gas, LLC, HRC Energy, LLC, The 7711 Corporation, Halcón Operating Co., Inc. and Halcón Field Services, LLC and Hawkwood Energy East Texas, LLC.
2.4	Stock Purchase Agreement dated January 24, 2017, by and among Halcón Resources Corporation and the Investors named on Schedule A thereto (Incorporated by referenced to Exhibit 2.1 of our Current Report on Form 8-K filed January 26, 2017).
3.1	Amended and Restated Certificate of Incorporation of Halcón Resources Corporation dated September 9, 2016 (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed September 9, 2016).
3.2	Fifth Amended and Restated Bylaws of Halcón Resources Corporation (Incorporated by reference to Exhibit 3.2 of our Current Report on Form 8-K filed May 7, 2015).
3.2.1	Amendment No. 1 to the Fifth Amended and Restated Bylaws of Halcón Resources Corporation (Incorporated by reference to Exhibit 3.2 of our Current Report on Form 8-K filed September 9, 2016).
4.1	Indenture, dated as of May 1, 2015, among Halcón Resources Corporation, the subsidiary guarantors named therein and U.S. Bank National Association, as trustee, relating to Halcón Resources Corporation's 8.625% Senior Secured Notes due 2020 (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed May 4, 2015).
4.1.1	First Supplemental Indenture, dated as of September 28, 2016, by and among Halcón Resources Corporation, the parties named therein as subsidiary guarantors, and U.S. Bank National Association, as Trustee, relating to the 8.625% Senior Secured Notes due 2020 (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed September 30, 2016).

4.1.2*	Second Supplemental Indenture, dated as of January 23, 2017, among Lampe, LLC, a subsidiary of Halcón Resources Corporation, the existing subsidiary guarantors and U.S. Bank National Association, as trustee, relating to the 8.625% Senior Secured Notes due 2020.
4.2	Indenture, dated as of December 21, 2015, among Halcón Resources Corporation, the guarantors named therein and U.S. Bank National Association, as Trustee, relating to Halcón Resources Corporation's 12.0% Second Lien Senior Secured Notes due 2022 (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed December 22, 2015).
4.2.1	First Supplemental Indenture dated as of September 28, 2016, by and among Halcón Resources Corporation, the parties named therein as subsidiary guarantors, and U.S. Bank National Association, as Trustee, relating to the 12.0% Second Lien Senior Secured Notes due 2022 (Incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K filed September 30, 2016).
4.2.2*	Second Supplemental Indenture dated as of January 23, 2017, among Lampe, LLC, a subsidiary of Halcón Resources Corporation, the existing subsidiary guarantors and U.S. Bank National Association, as trustee, relating to the 12.0% Second Lien Senior Secured Notes due 2022.
4.3	Purchase Agreement, dated February 9, 2017, by and among the Company, the Guarantors and J.P. Morgan Securities LLC, as representative of the Initial Purchasers named therein (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed February 10, 2017).
4.4*	Indenture, dated as of February 16, 2017, among Halcón Resources Corporation, the guarantors named therein and U.S. Bank National Association, as Trustee (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed February 16, 2017).
4.5	Registration Rights Agreement, dated as of February 16, 2017, by and among the Company, the Guarantors and J.P. Morgan Securities, LLC as representatives of the Initial Purchasers (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed February 16, 2017).
10.1	Senior Secured Revolving Credit Agreement, dated as of September 9, 2016, by and among Halcón Resources Corporation, JPMorgan Chase Bank, N.A., as administrative agent, and certain other financial institutions party thereto, as lenders (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed September 9, 2016).
10.2	Intercreditor Agreement, dated as of May 1, 2015, among Halcón Resources Corporation, the subsidiary guarantors named therein, U.S. Bank National Association, as second lien collateral trustee, and JPMorgan Chase Bank, N.A., as priority lien agent for the lenders (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed May 4, 2015).
10.2.1	Priority Confirmation Joinder, dated as of December 21, 2015, by and between JPMorgan Chase Bank, N.A., as Priority Lien Agent, U.S. Bank National Association, as New Representative, U.S. Bank National Association as Second Lien Collateral Trustee, and U.S. Bank National Association, as Third Lien Collateral Trustee (Incorporated by reference to Exhibit 10.3 of our Current Report on Form 8-K filed December 22, 2015).

10.3	Collateral Trust Agreement, dated as of May 1, 2015, among Halcón Resources Corporation, the subsidiary guarantors named therein and U.S. Bank National Association, as trustee, the other parity lien debt representatives from time to time party thereto and U.S. Bank National Association, as collateral trustee (Incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K filed May 4, 2015).
10.3.1	Collateral Trust Joinder, dated as of December 21, 2015, by U.S. Bank National Association, as New Notes Trustee, and U.S. Bank National Association, as Collateral Trustee (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed December 22, 2015).
10.4	Second Lien Security Agreement, dated as of May 1, 2015, among Halcón Resources Corporation, the subsidiary guarantors named therein and U.S. Bank National Association, as collateral trustee (Incorporated by reference to Exhibit 10.3 of our Current Report on Form 8-K filed May 4, 2015).
10.4.1	First Amendment to Second Lien Security Agreement, dated as of December 21, 2015, among Halcón Resources Corporation, the subsidiary guarantors named therein and U.S. Bank National Association, as collateral trustee (Incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K filed December 22, 2015).
10.5	Registration Rights Agreement, dated as of September 9, 2016, by and among Halcón Resources Corporation and the Holders parties thereto (Incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K filed September 9, 2016).
10.6	Warrant Agreement, dated as of September 9, 2016, by and between Halcón Resources Corporation and U.S. Bank National Association, as warrant agent (Incorporated by reference to Exhibit 10.3 of our Current Report on Form 8-K filed September 9, 2016).
10.7†	Halcón Resources Corporation 2016 Long-Term Incentive Plan, effective as of September 9, 2016 (Incorporated by reference to Exhibit 10.4 of our Current Report on Form 8-K filed September 9, 2016).
10.8	Assignment and Assumption Agreement, dated as of September 30, 2016, among Halcón Energy Properties, Inc., Halcón Gulf States, LLC and Apollo HK TMS Investment Holdings, L.P. (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed October 5, 2016).
10.9	Form of Indemnity Agreement between Halcón Resources Corporation and each of its directors (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed March 19, 2012).
10.10†	Employment Agreement between Floyd C. Wilson and Halcón Resources Corporation dated June 1, 2012 (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed June 5, 2012).
10.11†	Employment Agreement between Stephen W. Herod and Halcón Resources Corporation dated June 1, 2012 (Incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K filed June 5, 2012).
10.12†	Employment Agreement between Mark J. Mize and Halcón Resources Corporation dated June 1, 2012 (Incorporated by reference to Exhibit 10.3 of our Current Report on Form 8-K filed June 5, 2012).
10.13†	Employment Agreement between David S. Elkouri and Halcón Resources Corporation dated June 1, 2012 (Incorporated by reference to Exhibit 10.4 of our Current Report on Form 8-K filed June 5, 2012).

10.14†	Employment Agreement between Joseph S. Rinando, III and Halcón Resources Corporation dated June 1, 2012 (Incorporated by reference to Exhibit 10.5 of our Current Report on Form 8-K filed June 5, 2012).
10.15†	Key Employee Retention Agreement between Floyd C. Wilson and Halcón Resources Corporation dated March 8, 2016 (Incorporated by reference to Exhibit 10.37 of our Annual Report on Form 10-K filed February 26, 2016, as amended by Amendment No. 1 filed on April 25, 2016).
10.16†	Key Employee Retention Agreement between Stephen W. Herod and Halcón Resources Corporation dated March 8, 2016 (Incorporated by reference to Exhibit 10.38 of our Annual Report on Form 10-K filed February 26, 2016, as amended by Amendment No. 1 filed on April 25, 2016).
10.17†	Key Employee Retention Agreement between Mark J. Mize and Halcón Resources Corporation dated March 8, 2016 (Incorporated by reference to Exhibit 10.39 of our Annual Report on Form 10-K filed February 26, 2016, as amended by Amendment No. 1 filed on April 25, 2016).
10.18†	Key Employee Retention Agreement between David S. Elkouri and Halcón Resources Corporation dated March 8, 2016 (Incorporated by reference to Exhibit 10.40 of our Annual Report on Form 10-K filed February 26, 2016, as amended by Amendment No. 1 filed on April 25, 2016).
10.19†*	Third Amended and Restated Summary of Non-Employee Director Compensation adopted effective as of on September 9, 2016.
10.20†	Amended and Restated Stock Ownership Guidelines Policy adopted on February 25, 2015 (Incorporated by reference to Exhibit 10.26 of our Annual Report on Form 10-K filed February 26, 2016, as amended by Amendment No. 1 filed on April 25, 2016).
10.21†*	Form of Employee Stock Option Award Agreement.
10.22†*	Form of Employee Restricted Stock Award Agreement.
10.23†*	Form of Non-Employee Director Restricted Stock Award Agreement.
12.1*	Computation of Ratio of Earnings to Combined Fixed Charges and Preference Dividends
21.1*	List of Subsidiaries of Halcón Resources Corporation
23.1*	Consent of Deloitte & Touche LLP
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Sarbanes-Oxley Section 302 certification of Principal Executive Officer
31.2*	Sarbanes-Oxley Section 302 certification of Principal Financial Officer
32*	Sarbanes-Oxley Section 906 certification of Principal Executive Officer and Principal Financial Officer
99.1*	Report of Netherland, Sewell & Associates, Inc.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Document

101.LAB*	XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

* *Attached hereto.*

† *Indicates management contract or compensatory plan or arrangement.*

The registrant has not filed with this report copies of the instruments defining rights of all holders of long-term debt of the registrant and its consolidated subsidiaries based upon the exception set forth in Item 601(b)(4)(iii)(A) of Regulation S-K. Copies of such instruments will be furnished to the SEC upon request.

SIGNATURES

Pursuant to the requirements 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.

HALCÓN RESOURCES CORPORATION

Date: February 28, 2017	By: /s/ FLOYD C. WILSON Floyd C. Wilson *Chairman of the Board,* *Chief Executive Officer and President*

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.

Signature	Title	Date
/s/ FLOYD C. WILSON Floyd C. Wilson	Chairman of the Board, Chief Executive Officer and President	February 28, 2017
/s/ MARK J. MIZE Mark J. Mize	Executive Vice President, Chief Financial Officer and Treasurer	February 28, 2017
/s/ JOSEPH S. RINANDO, III Joseph S. Rinando, III	Senior Vice President, Chief Accounting Officer and Controller	February 28, 2017
/s/ WILLIAM J. CAMPBELL William J. Campbell	Director	February 28, 2017
/s/ JAMES W. CHRISTMAS James W. Christmas	Lead Director	February 28, 2017
/s/ MICHAEL L. CLARK Michael L. Clark	Director	February 28, 2017
/s/ THOMAS R. FULLER Thomas R. Fuller	Director	February 28, 2017

Signature	Title	Date
/s/ DARRYL L. SCHALL Darryl Schall	Director	February 28, 2017
/s/ RONALD D. SCOTT Ronald D. Scott	Director	February 28, 2017
/s/ ERIC G. TAKAHA Eric G. Takaha	Director	February 28, 2017
/s/ NATHAN W. WALTON Nathan W. Walton	Director	February 28, 2017

Exhibit 12.1

Computation of Ratio of Earnings to Combined Fixed Charges and Preference Dividends
(In thousands, except ratios)

	Successor	Predecessor				
	Period from September 10, 2016 through December 31, 2016	Period from January 1, 2016 through September 9, 2016	Years Ended December 31,			
			2015	2014	2013	2012
Earnings:						
Income (loss) before income taxes	$(474,449)	$ 3,292	$(1,913,535)	$ 314,880	$(1,380,378)	$ (67,066)
Adjustments:						
Equity investment loss (income)	(9)	152	171	(617)	(97)	(373)
Interest capitalized	—	(68,192)	(113,009)	(168,897)	(203,993)	(53,492)
Income (loss) before income taxes, as adjusted	$(474,458)	$ (64,748)	$(2,026,373)	$ 145,366	$(1,584,468)	$(120,931)
Fixed charges	29,013	197,640	340,399	320,403	262,046	86,589
Total earnings	$(445,445)	$132,892	$(1,685,974)	$ 465,769	$(1,322,422)	$ (34,342)
Fixed charges:						
Interest expense and amortization of finance costs	$ 28,553	$195,698	$ 337,554	$ 317,732	$ 259,159	$ 85,372
Rental expense representative of interest factor	460	1,942	2,845	2,671	2,887	1,217
Total fixed charges	$ 29,013	$197,640	$ 340,399	$ 320,403	$ 262,046	$ 86,589
Ratio of earnings to fixed charges	—(1)	—(3)	—(5)	1.5	—(7)	—(8)
Total fixed charges	$ 29,013	$197,640	$ 340,399	$ 320,403	$ 262,046	$ 86,589
Pre-tax preferred dividend requirements	783	12,320	83,942	32,902	12,132	110,075
Total fixed charges plus preference dividends	$ 29,796	$209,960	$ 424,341	$ 353,305	$ 274,178	$ 196,664
Ratio of earnings to combined fixed charges and preference dividends	—(2)	—(4)	—(6)	1.3	—(7)	—(9)

(1) *Due to the Company's loss for the period from September 10, 2016 through December 31, 2016 the ratio coverage was less than 1:1. The Company must generate additional earnings of $474.5 million to achieve a coverage ratio of 1:1.*

(2) *Due to the Company's loss for the period from September 10, 2016 through December 31, 2016 the ratio coverage was less than 1:1. The Company must generate additional earnings of $475.2 million to achieve a coverage ratio of 1:1.*

(3) *Due to the Company's loss for the period from January 1, 2016 through September 9, 2016 the ratio coverage was less than 1:1. The Company must generate additional earnings of $64.7 million to achieve a coverage ratio of 1:1.*

(4) *Due to the Company's loss for the period from January 1, 2016 through September 9, 2016 the ratio coverage was less than 1:1. The Company must generate additional earnings of $77.1 million to achieve a coverage ratio of 1:1.*

(5) *Due to the Company's "Loss before income taxes, as adjusted" in 2015, the ratio coverage was less than 1:1. The Company must generate additional earnings of $2.0 billion to achieve coverage ratio of 1:1.*

(6) *Due to the Company's "Loss before income taxes, as adjusted" in 2015, the ratio coverage was less than 1:1. The Company must generate additional earnings of $2.1 billion to achieve coverage ratio of 1:1.*

(7) *Due to the Company's "Loss before income taxes, as adjusted" in 2013, the ratio coverage was less than 1:1. The Company must generate additional earnings of $1.6 billion to achieve a coverage ratio of 1:1.*

(8) *Due to the Company's "Loss before income taxes, as adjusted" in 2012, the ratio coverage was less than 1:1. The Company must generate additional earnings of $120.9 million to achieve a coverage ratio of 1:1.*

(9) *Due to the Company's "Loss before income taxes, as adjusted" in 2012, the ratio coverage was less than 1:1. The Company must generate additional earnings of $231.0 million to achieve a coverage ratio of 1:1.*

Exhibit 21.1

Subsidiaries of the Registrant

Subsidiary	State of Incorporation or Organization
Halcón Resources Operating, Inc	Delaware
Halcón Holdings, Inc.	Delaware
HRC Energy Resources (WV), Inc.	Delaware
HRC Energy Louisiana, LLC	Delaware
HRC Production Company.	Texas
Halcón Energy Properties, Inc.	Delaware
Halcón Operating Co., Inc.	Texas
Halcón Gulf States, LLC	Oklahoma
Halcón Energy Holdings, LLC	Delaware
Halcón Field Services, LLC	Delaware
Halcón Louisiana Operating, L.P.	Delaware
HRC Energy, LLC	Colorado
HRC Operating, LLC	Colorado
HK Oil & Gas, LLC	Texas
Halcón Williston I, LLC	Texas
Halcón Williston II, LLC	Texas
HK Energy, LLC	Texas
HK Louisiana Operating, LLC	Texas
HK Energy Operating, LLC.	Texas
HK Resources, LLC	Delaware
The 7711 Corporation	Texas
Lampe, LLC	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-213565, on Form S-8, of our reports dated February 28, 2017, relating to the financial statements of Halcón Resources Corporation, and the effectiveness of Halcón Resources Corporation's internal control over financial reporting, appearing in this Annual Report on Form 10-K of Halcón Resources Corporation for the year ended December 31, 2016.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 28, 2017

Exhibit 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

As independent petroleum engineers, we hereby consent to the references to our firm, in the context in which they appear, and to the references to and the incorporation by reference of our reserves report dated February 1, 2017, included in the Annual Report on Form 10-K of Halcón Resources Corporation (the "Company") for the fiscal year ended December 31, 2016, as well as in the notes to the financial statements included therein. We also hereby consent to the incorporation by reference of the references to our firm, in the context in which they appear, and to our reserves report dated February 1, 2017, into the Registration Statement on and Form S-8 (File No. 333-213565), filed with the U.S. Securities and Exchange Commission.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ DANNY D. SIMMONS

Danny D. Simmons, P.E.
President and Chief Operating Officer

Houston, Texas
February 28, 2017

Exhibit 31.1

CERTIFICATION

I, Floyd C. Wilson, certify that:

1. I have reviewed this Annual Report on Form 10-K of Halcón Resources Corporation;

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; and

   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 control over financial reporting.

Date: February 28, 2017

By: /s/ FLOYD C. WILSON

Floyd C. Wilson
Chairman of the Board, Chief Executive Officer and President

Exhibit 31.2

CERTIFICATION

I, Mark J. Mize, certify that:

1. I have reviewed this Annual Report on Form 10-K of Halcón Resources Corporation;

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; and

    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 control over financial reporting.

Date: February 28, 2017

By: /s/ MARK J. MIZE

Mark J. Mize
Executive Vice President, Chief Financial Officer and Treasurer

Exhibit 32

Certification Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002
(Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code)

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code), Floyd C. Wilson, Chairman of the Board, Chief Executive Officer and President, and Mark J. Mize, Executive Vice President, Chief Financial Officer and Treasurer, of Halcón Resources Corporation, (the "Company"), each hereby certifies that, to the best of his knowledge:

(1) The Company's Annual Report on Form 10-K for the year ended December 31, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 28, 2017

/s/ FLOYD C. WILSON

Floyd C. Wilson
Chairman of the Board, Chief Executive Officer and President

February 28, 2017

/s/ MARK J. MIZE

Mark J. Mize
Executive Vice President, Chief Financial Officer and Treasurer

This certification accompanies this Form 10-K and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, or otherwise subject to the liability of that Section.

A signed original of this written statement required by Section 906 has been provided to, and will be retained by, the Company and furnished to the Securities and Exchange Commission or its staff upon request.