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

FORM 10-K

(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2018

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from _____ to _____

Commission File No. 001-03262

COMSTOCK RESOURCES, INC.
(Exact name of registrant as specified in its charter)

NEVADA	**94-1667468**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

5300 Town and Country Blvd., Suite 500, Frisco, Texas 75034
(Address of principal executive offices including zip code)

(972) 668-8800
(Registrant's telephone number and area code)

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

Common Stock, $.50 Par Value	**New York Stock Exchange**
(Title of class)	(Name of exchange on which registered)

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

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

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

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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 a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer", "accelerated filer", "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	____	Accelerated filer	✓	Non-accelerated filer	____	Smaller reporting company	✓
Emerging growth company	____						

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

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

The aggregate market value of the common stock held by non-affiliates of the registrant, based on the closing price of common stock on the New York Stock Exchange on June 29, 2018 (the last business day of the registrant's most recently completed second fiscal quarter), was $152.5 million.

As of March 1, 2019, there were 105,871,064 shares of common stock of the registrant outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Definitive Proxy Statement for the 2019 Annual Meeting of Stockholders are incorporated by reference into Part III of this report.

COMSTOCK RESOURCES, INC.
ANNUAL REPORT ON FORM 10-K
For the Fiscal Year Ended December 31, 2018

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

The information contained in this report includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These forward-looking statements are identified by their use of terms such as "expect," "estimate," "anticipate," "project," "plan," "intend," "believe" and similar terms. All statements, other than statements of historical facts, included in this report, are forward-looking statements, including statements mentioned under "Risk Factors" and "Management's Discussion and Analysis of Financial Condition and Results of Operations," regarding:

- amount and timing of future production of oil and natural gas;
- amount, nature and timing of capital expenditures;
- the number of anticipated wells to be drilled after the date hereof;
- the availability of exploration and development opportunities;
- our financial or operating results;
- our cash flow and anticipated liquidity;
- operating costs including lease operating expenses, administrative costs and other expenses;
- finding and development costs;
- our business strategy; and
- other plans and objectives for future operations.

Any or all of our forward-looking statements in this report may turn out to be incorrect. They can be affected by a number of factors, including, among others:

- the risks described in "Risk Factors" and elsewhere in this report;
- the volatility of prices and supply of, and demand for, oil and natural gas;
- the timing and success of our drilling activities;
- the numerous uncertainties inherent in estimating quantities of oil and natural gas reserves and actual future production rates and associated costs;
- our ability to successfully identify, execute or effectively integrate future acquisitions;
- the usual hazards associated with the oil and natural gas industry, including fires, well blowouts, pipe failure, spills, explosions and other unforeseen hazards;
- our ability to effectively market our oil and natural gas;
- the availability of rigs, equipment, supplies and personnel;
- our ability to discover or acquire additional reserves;
- our ability to satisfy future capital requirements;
- changes in regulatory requirements;
- general economic conditions, status of the financial markets and competitive conditions; and
- our ability to retain key members of our senior management and key employees.

DEFINITIONS

The following are abbreviations and definitions of terms commonly used in the oil and gas industry and this report. Natural gas equivalents and crude oil equivalents are determined using the ratio of six Mcf to one barrel. All references to "us", "our", "we" or "Comstock" mean the registrant, Comstock Resources, Inc. and where applicable, its consolidated subsidiaries.

"Bbl" means a barrel of U.S. 42 gallons of oil.

"Bcf" means one billion cubic feet of natural gas.

"Bcfe" means one billion cubic feet of natural gas equivalent.

"BOE" means one barrel of oil equivalent.

"Btu" means British thermal unit, which is the quantity of heat required to raise the temperature of one pound of water from 58.5 to 59.5 degrees Fahrenheit.

"Completion" means the installation of permanent equipment for the production of oil or gas.

"Condensate" means a hydrocarbon mixture that becomes liquid and separates from natural gas when the gas is produced and is similar to crude oil.

"Development well" means a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

"Dry hole" means 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.

"Exploratory well" means a well drilled to find a new field or to find a new productive reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known reservoir.

"Gross" when used with respect to acres or wells, production or reserves refers to the total acres or wells in which we or another specified person has a working interest.

"LNG" refers to liquefied natural gas, which is a composition of methane and some mixture of ethane that has been cooled to liquid form for ease and safety of non-pressurized storage or transport.

"MBbls" means one thousand barrels of oil.

"MBbls/d" means one thousand barrels of oil per day.

"Mcf" means one thousand cubic feet of natural gas.

"Mcfe" means one thousand cubic feet of natural gas equivalent.

"MMBbls" means one million barrels of oil.

"MMBOE" means one million barrels of oil equivalent.

"MMBtu" means one million British thermal units.

"MMcf" means one million cubic feet of natural gas.

"MMcf/d" means one million cubic feet of natural gas per day.

"MMcfe/d" means one million cubic feet of natural gas equivalent per day.

"MMcfe" means one million cubic feet of natural gas equivalent.

"Net" when used with respect to acres or wells, refers to gross acres of wells multiplied, in each case, by the percentage working interest owned by us.

"Net production" means production we own less royalties and production due others.

"Oil" means crude oil or condensate.

"Operator" means the individual or company responsible for the exploration, development, and production of an oil or gas well or lease.

"Proved developed reserves" means reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

"Proved developed non-producing" means reserves (i) expected to be recovered from zones capable of producing but which are shut-in because no market outlet exists at the present time or whose date of connection to a pipeline is uncertain or (ii) currently behind the pipe in existing wells, which are considered proved by virtue of successful testing or production of offsetting wells.

"Proved developed producing" means reserves expected to be recovered from currently producing zones under continuation of present operating methods. This category includes recently completed shut-in gas wells scheduled for connection to a pipeline in the near future.

"Proved reserves" means the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided by contractual arrangements.

"Proved undeveloped reserves" means reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling locations offsetting productive wells that are reasonably certain of production when drilled or where it can be demonstrated with certainty that there is continuity of production from the existing productive formation.

"PV 10 Value" means the present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with SEC guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service, future income tax expense and depreciation, depletion and amortization, and discounted using an annual discount rate of 10%. This amount is the same as the standardized measure of discounted future net cash flows related to proved oil and natural gas reserves except that it is determined without deducting future income taxes. Although PV 10 Value is not a financial measure calculated in accordance with GAAP, management believes that the presentation of PV 10 Value is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account corporate future income taxes and our current tax structure. We use this measure when assessing the potential return on investment related to our oil and gas properties. Because many factors that are unique to any given company affect the amount of estimated future income taxes, we believe the use of a pre-tax measure is helpful to investors when comparing companies in our industry.

"Recompletion" means the completion for production of an existing well bore in another formation from which the well has been previously completed.

"Reserve life" means the calculation derived by dividing year-end reserves by total production in that year.

"Royalty" means an interest in an oil and gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

"3-D seismic" means an advanced technology method of detecting accumulations of hydrocarbons identified by the collection and measurement of the intensity and timing of sound waves transmitted into the earth as they reflect back to the surface.

"SEC" means the United States Securities and Exchange Commission.

"Tcf" means one trillion cubic feet of natural gas.

"Tcfe" means one trillion cubic feet of natural gas equivalent.

"Working interest" means an interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce oil and gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations. The share of production to which a working interest owner is entitled will always be smaller than the share of costs that the working interest owner is required to bear, with the balance of the production accruing to the owners of royalties. For example, the owner of a 100% working interest in a lease burdened only by a landowner's royalty of 12.5% would be required to pay 100% of the costs of a well but would be entitled to retain 87.5% of the production.

"Workover" means operations on a producing well to restore or increase production.

PART I

ITEMS 1 and 2. *BUSINESS AND PROPERTIES*

We are a disciplined, growth-oriented, independent energy company focused on creating value through the development of our substantial inventory of highly economic and low-risk drilling opportunities in the Haynesville and Bossier shale. Our common stock is listed and traded on the New York Stock Exchange under the symbol "CRK".

On August 14, 2018, Arkoma Drilling, L.P. and Williston Drilling, L.P. (collectively, the "Jones Partnerships") contributed certain oil and gas properties in North Dakota and Montana in exchange for 88,571,429 newly issued shares of our common stock representing 84% of the Company's outstanding common stock (the "Jones Contribution"). The Jones Partnerships are wholly owned and controlled by Dallas businessman Jerry Jones and his children (collectively, the "Jones Group"). References to "Successor" or "Successor Company" relate to the operations of the Company subsequent to August 13, 2018. Reference to "Predecessor" or "Predecessor Company" relate to the operations of the Company on or prior to August 13, 2018.

Our oil and gas operations are primarily concentrated in Louisiana, Texas and North Dakota. Our oil and natural gas properties are estimated to have proved reserves of 2.4 Tcfe with a PV 10 Value of $1.8 billion as of December 31, 2018. Our proved oil and natural gas reserve base is 94% natural gas and 6% oil and was 29% developed as of December 31, 2018, and our properties have an average reserve life of approximately 17 years.

Our proved reserves at December 31, 2018 and our 2018 average daily production are summarized below:

	Proved Reserves at December 31, 2018			
	Oil (MMBbls)	Natural Gas (Bcf)	Total (Bcfe)	% of Total
Haynesville/Bossier shale	—	2,187.6	2,187.6	90%
Bakken shale	21.6	47.4	176.9	7%
Cotton Valley	0.3	44.1	45.7	2%
Eagle Ford shale	1.6	1.1	10.9	1%
Other	0.1	2.6	3.3	—%
Total	23.6	2,282.8	2,424.4	100%

	Average Daily Production Successor Period - August 14, 2018 through December 31, 2018			
	Oil (MBbls/d)	Natural Gas (MMcf/d)	Total (MMcfe/d)	% of Total
Haynesville/Bossier shale	—	281.5	281.5	74%
Bakken shale	9.7	27.5	86.0	23%
Cotton Valley	0.1	11.6	12.2	3%
Other	0.1	1.0	1.3	—%
Total	9.9	321.6	381.0	100%

	Average Daily Production Predecessor Period - January 1, 2018 through August 13, 2018			
	Oil (MBbls/d)	Natural Gas (MMcf/d)	Total (MMcfe/d)	% of Total
Haynesville/Bossier shale	—	231.2	231.2	91%
Cotton Valley	0.1	10.5	11.2	5%
Eagle Ford shale	1.1	1.7	8.3	3%
Other	0.1	2.1	2.5	1%
Total	1.3	245.5	253.2	100%

Strengths

High Quality Properties. As of December 31, 2018, we have accumulated 116,866 acres (87,270 net to us) in the Haynesville and Bossier shale plays, located in the North Louisiana parishes of Bossier, Caddo, DeSoto and Sabine and the Texas counties of Harrison, Panola, Rusk and Shelby. Approximately 83% of our Haynesville/Bossier shale net acreage is held-by-production and our Haynesville/Bossier shale properties have extensive development and exploration potential. Advances in drilling and completion technology have allowed us to increase the reserves recovered through longer horizontal lateral length and substantially larger well stimulation. As a result of the improved economic returns, we have focused our development activities primarily on drilling Haynesville and Bossier horizontal wells in recent years.

Our Haynesville and Bossier shale positions in North Louisiana and East Texas are located in one of the premier North American natural gas shale plays and we believe our liquids-rich Eagle Ford shale position offers substantial, highly economic and low-risk drilling opportunities. We intend to prudently redeploy the cash flow generated by our properties in the Bakken shale to develop our Haynesville, Bossier and Eagle Ford shale undeveloped locations while maintaining sufficient liquidity and a low leverage profile. We believe we are well positioned for future growth due to the following:

- *De-risked, contiguous and prolific oil and natural gas resources*. The Haynesville and Bossier shale plays have been substantially delineated since 2008 through the drilling of over 4,100 horizontal wells. We believe that these shale plays represent some of the most consistent and prolific natural gas development drilling opportunities in North America.
- *Management and operating team with extensive experience in developing the Haynesville and Bossier shale plays*. We were among the first exploration and production companies to effectively apply horizontal drilling techniques in the Haynesville and Bossier shales beginning in 2007. Since then, our management and operating team initiated a drilling program in the Haynesville and Bossier shales in 2015 based on a new, enhanced completion well design that significantly improved the economics of these wells in comparison to the 189 wells we drilled from 2008 to 2013. We have drilled and completed a total of 70 operated wells (47.0 net to us) targeting the Haynesville or Bossier shale from 2015 through December 2018 employing this enhanced completion design. These wells had an average per well initial production rate of 25 MMcf per day.
- *Attractive economic returns*. The Haynesville, Bossier and Eagle Ford shales offer highly economic and low-risk drilling opportunities through application of advanced drilling and completion technologies, including the use of longer laterals, and high intensity fracture stimulation using tighter frac stages and higher proppant loading. Our management and operating team has been instrumental in developing and optimizing some of the most effective completion techniques in the Haynesville and Bossier shales and such completion techniques have resulted in a material improvement in initial production rates and recoverable reserves, and has resulted in some of the highest single well rates of return when compared to results from other natural gas basins in North America.
- *Proximity to premium natural gas markets*. Our natural gas production benefits from the strong regional Gulf Coast demand growth driven by a substantial increase in LNG exports, greater natural gas exports to Mexico and new or expanded petrochemical facilities. Producers, such as us, with access to the Gulf Coast natural gas markets are receiving higher net realized prices than most producers in other regions. We are also able to realize higher margins due to our ability to access the extensive midstream infrastructure at attractive rates and lack of above-market midstream commitments.

Value-Added Acquisitions. During 2018 we completed two acquisitions of acreage and producing properties near our existing acreage. We acquired 17,386 net acres prospective for Haynesville shale development with 225 (66.4 net) drilling locations in two transactions. The acreage along with interests in 114 (27.8 net) producing wells was acquired for $41.5 million along with an obligation to provide $20.5 million in future drilling and completion costs on wells drilled on the acreage. We also reacquired working interests from Arkoma Drilling, L.P. for $17.9 million as part of the termination of the strategic drilling venture entered into prior to the closing of the Jones Contribution. The acquisitions completed in 2018 added 253.7 Bcfe to our proved reserves which had a PV 10 Value of $126.9 million.

Successful Drilling Program. We spent $271.7 million on development activities in 2018, with $224.4 million on development activity in the Haynesville and Bossier shale. We spent $197.2 million on drilling and completing horizontal Haynesville and Bossier shale wells and an additional $27.2 million on refrac and other development activity. We drilled 49 (17.0 net) horizontal Haynesville and Bossier wells in 2018, which had an average lateral length of approximately 8,300 feet. We also completed 16 (4.2 net) wells that were drilled in 2017. Thirty (11.9 net) of the wells drilled in 2018 were also completed in 2018. We expect that the remaining 16 (5.7 net) wells will be completed in 2019. Our natural gas drilling program in 2018 was the major driver for the increase in our natural gas production of 36% over 2017 and contributed to the 104% growth we had in our natural gas reserves from 2017. We also spent $42.7 million of development costs on our other properties primarily on completing 24 (7.0 net) Bakken shale wells and $4.6 million on leasehold costs.

Efficient Operator. We operated 86% of our proved reserve base as of December 31, 2018. As the operator, we are better able to control operating costs, the timing and plans for future development, the level of drilling and lifting costs and the marketing of production. As an operator, we receive reimbursements for overhead from other working interest owners, which reduces our general and administrative expenses.

Business Strategy

Our strategy consists of the following principal elements:

- *Prudently grow cash flow, production and reserves through the development of our extensive drilling inventory in the Haynesville, Bossier and Eagle Ford shales.* We have an extensive inventory of horizontal well drilling locations prospective for the Haynesville and Bossier shales, providing us with years of inventory of development locations. The following outlines our Haynesville and Bossier shale future drilling locations by lateral length as we currently plan to drill them:

	Haynesville Shale					
Horizontal	Operated		Non-Operated		Total	
Lateral Length	(Gross)	(Net)	(Gross)	(Net)	(Gross)	(Net)
Less than 5,000 feet	186	139.2	351	48.1	537	187.3
5,000 feet to 8,000 feet	111	86.9	33	4.4	144	91.3
Greater than 8,000 feet	221	158.6	52	6.3	273	164.9
	518	384.7	436	58.8	954	443.5

	Bossier Shale					
Horizontal	Operated		Non-Operated		Total	
Lateral Length	(Gross)	(Net)	(Gross)	(Net)	(Gross)	(Net)
Less than 5,000 feet	155	119.5	161	21.9	316	141.4
5,000 feet to 8,000 feet	98	78.9	8	1.9	106	80.8
Greater than 8,000 feet	192	152.2	2	1.0	194	153.2
	445	350.6	171	24.8	616	375.4
Total	963	735.3	607	83.6	1,570	818.9

We have 21,482 (9,432 net to us) undeveloped acres prospective for development in the oil window of the Eagle Ford shale in South Texas. We have entered into a joint development venture with our acreage and have the opportunity to participate in the drilling of 225 (126.0 net to us) wells.

Since much of our net acreage is held by production, we have the ability to allocate capital among projects in a manner that optimizes both costs and returns, resulting in a highly efficient drilling program. We intend to manage the selection of drilling locations and the timing of development and associated capital expenditures in order to economically grow our cash flow, production and reserves while funding our capital expenditures primarily with operating cash flow.

- *Enhance returns through a focus on optimizing full cycle economics*. We continually monitor and adjust our drilling program on a regular basis with the objective of achieving the most economical returns on our portfolio of drilling opportunities. We believe that we will achieve this objective by (i) minimizing our costs to drill and complete wells, (ii) maximizing well production and recoveries by optimizing lateral length, the number of frac stages, perforation intervals and the type of fracture stimulation employed, (iii) producing near pipeline-quality natural gas, which leads to lower processing costs, and (iv) minimizing operating costs through efficient well management.
- *Evaluate and pursue strategic acquisition opportunities to grow our reserves, production, and acreage position.* We intend to leverage our management and operating team's significant technical expertise and experience in successfully executing and integrating acquisitions to continue pursuing acquisition opportunities that will add to our drilling inventory.
- *Maintain disciplined financial strategy.* We believe we are in a strong financial position, and we intend to maintain a conservative balance sheet with lower leverage and adequate liquidity to fund our development program, effectively allocate capital, and continuously improve our cost structure. We intend to pursue a development plan that will be substantially funded with operating cash flow. If necessary, we will use borrowings under our bank credit facility to help fund our development plan, while prudently managing our capital structure, leverage and liquidity.
- *Manage commodity price exposure through an active hedging program to protect our expected future cash flows.* We expect to maintain an active oil and natural gas price hedging program designed to mitigate volatility in oil and natural gas prices and to protect a portion of our expected future cash flows.

Primary Operating Areas

The following table summarizes the estimated proved oil and natural gas reserves as of December 31, 2018:

	Oil (MBbls)	Natural Gas (MMcf)	Total (MMcfe)(1)	%	PV 10 Value (000's)(2)	%
Haynesville/Bossier Shale	—	2,187,598	2,187,598	90%	$ 1,166,389	67%
Bakken Shale	21,580	47,373	176,855	7%	541,227	31%
Cotton Valley	274	44,092	45,734	2%	36,394	2%
Eagle Ford Shale	1,645	1,066	10,933	1%	7,406	—%
Other	113	2,629	3,311	—%	3,729	—%
Total	23,612	2,282,758	2,424,431	100%	$ 1,755,145	100%

(1) Oil is converted to natural gas equivalents by using a conversion factor of one barrel of oil for six Mcf of natural gas based upon the approximate relative energy content of oil to natural gas, which is not indicative of oil and natural gas prices.

(2) The PV10 Value represents the discounted future net cash flows attributable to our proved oil and gas reserves before income tax, discounted at 10%. Although it is a non-GAAP measure, we believe that the presentation of PV 10 Value is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account corporate future income taxes and our current tax structure. We use this measure when assessing the potential return on investment related to our oil and gas properties. The standardized measure of discounted future net cash flows represents the present value of future cash flows attributable to our proved oil and gas reserves after income tax, discounted at 10%.

Haynesville/Bossier Shale

Approximately 90%, or 2.2 Tcfe of our proved reserves, are located in the Haynesville and Bossier shales in East Texas and North Louisiana, where we own interests in 306 producing wells (171.3 net to us). We operate 191 of these wells. The wells produce from the Bossier shale at depths of 10,500 to 12,100 feet and from the Haynesville shale at depths from 10,500 to 12,950 feet. Our production from the Haynesville and Bossier shale averaged 251 MMcf of natural gas per day in 2018. We spent $197.2 million in 2018 drilling 49 wells (17.0 net to us) and completing 16 (4.2 net) wells that were drilled in 2017. We spent $27.2 million on refrac and other development activity in this region in 2018. We also completed two acquisitions in 2018 acquiring 17,386 net acres and 47 producing wells in the Haynesville and Bossier shale. We currently plan to spend approximately $339.8 million in 2019 to drill 58 (36.4 net) wells and to complete an additional 16 (5.7 net to us) wells we drilled in 2018.

Bakken Shale

Approximately 7% (177 Bcfe) of our proved reserves are located in North Dakota and Montana, where we own interests in 424 producing wells (65.8 net to us) which produce from the Bakken shale. The Bakken shale proved reserves are 73% oil and represent 31% of our PV 10 Value. We acquired 403 non-operated wells (60.3 net to us) in the Bakken shale with the Jones Contribution and we participated in the completion of 24 wells (7.0 net to us) at a cost of $42.7 million. Net daily production rates from our Bakken shale properties averaged 9,743 barrels of oil and 27.5 MMcf of natural gas per day in 2018.

Cotton Valley

Approximately 2%, or 46 Bcfe of our proved reserves, are located primarily in the Cotton Valley formations in East Texas and North Louisiana, where we own interests in 651 producing wells (368.8 net to us). These wells produce from multiple sands at a depth of 8,000 to 10,000 feet. We operate 416 of these wells. Our Cotton Valley wells averaged 10.9 MMcf of natural gas per day and 112 barrels of oil per day in 2018. Future drilling opportunities include approximately 317 horizontal wells (216.1 net to us).

Eagle Ford Shale

Approximately 11 Bcfe of our proved reserves are located in South Texas that are prospective for production from the Eagle Ford shale. Our proved reserves in this field are estimated to be 1.8 MMBOE (10.9 Bcfe) (90% oil) and represent less than 1% of our total proved reserves. The Eagle Ford shale is found between 7,500 feet and 11,500 feet across our acreage position. We have 21,482 (9,452 net to us) undeveloped acres that are subject to a joint development agreement under which we have the opportunity to participate in up to 225 wells (126.0 net to us) in the future. In 2019 we plan to drill four Eagle Ford shale wells (1.9 net to us).

Other Regions

Less than 1%, or 3.3 Bcfe, of our proved reserves are in other regions, primarily in New Mexico and the Mid-Continent region. We own interests in 243 producing wells (28.9 net to us) in eight fields within these regions. Net daily production from our other regions during 2018 totaled 1.7 MMcf of natural gas and 55 barrels of oil or 2 MMcfe per day.

Oil and Natural Gas Reserves

The following table sets forth our estimated proved oil and natural gas reserves as of December 31, 2018:

	Oil (MBbls)	Natural Gas (MMcf)	Total (MMcfe)	PV 10 Value (000's)(1)
Proved Developed:				
Producing	20,939	543,741	669,374	$1,127,449
Non-producing	527	39,366	42,528	48,436
Total Proved Developed	21,466	583,107	711,902	1,175,885
Proved Undeveloped	2,146	1,699,651	1,712,529	579,260
Total Proved	23,612	2,282,758	2,424,431	1,755,145
Discounted Future Income Taxes				(281,305)
Standardized Measure of Discounted Cash Flows				$1,473,840

(1) The PV 10 Value represents the discounted future net cash flows attributable to our proved oil and gas reserves before income tax, discounted at 10%. Although it is a non-GAAP measure, we believe that the presentation of PV 10 Value is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account corporate future income taxes and our current tax structure. We use this measure when assessing the potential return on investment related to our oil and gas properties. The standardized measure of discounted future net cash flows represents the present value of future cash flows attributable to our proved oil and gas reserves after income tax, discounted at 10%.

The following table sets forth our year end reserves as of December 31 for each of the last three fiscal years:

	2016		2017		2018	
	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
Proved Developed	7,277	321,527	7,552	436,114	21,466	583,107
Proved Undeveloped	—	550,941	—	680,842	2,146	1,699,651
Total Proved Reserves	7,277	872,468	7,552	1,116,956	23,612	2,282,758

Proved reserves that are attributable to existing producing wells are primarily determined using decline curve analysis and rate transient analysis, which incorporates the principles of hydrocarbon flow. Proved reserves attributable to producing wells with limited production history and for undeveloped locations are estimated using performance from analogous wells in the surrounding area and geologic data to assess the reservoir continuity. Technologies relied on to establish reasonable certainty of economic producibility include electrical logs, radioactivity logs, core analyses, geologic maps and available production data, seismic data and well test data.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

The average prices that we realized from sales of oil and natural gas and lifting costs including severance and ad valorem taxes and transportation costs, for each of the last three fiscal years were as follows:

	Predecessor			Successor
	Year Ended December 31,		For the Period from January 1, 2018 through August 13,	For the Period from August 14, 2018 through December 31,
	2016	2017	2018	2018
Oil Price - $/Bbl	$ 38.24	$ 49.02	$65.23	$ 57.34
Natural Gas Price - $/Mcf	$ 2.28	$ 2.84	$ 2.68	$ 3.20
Lifting Costs - $/Mcfe	$ 1.10	$ 0.77	$ 0.64	$ 0.79

Prices used in determining quantities of oil and natural gas reserves and future cash inflows from oil and natural gas reserves represent the average first of the month prices received at the point of sale for the last twelve months. These prices have been adjusted from posted prices for both location and quality differences. The oil and natural gas prices used for reserves estimation were as follows:

Year	Oil Price (per Bbl)	Natural Gas Price (per Mcf)
2016	$ 37.62	$ 2.29
2017	$ 48.71	$ 2.88
2018	$ 61.21	$ 2.90

Reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered, and they are scheduled to be drilled within five years of their initial inclusion as proved reserves, unless specific circumstances justify a longer time. In connection with estimating proved undeveloped reserves for our reserve report, reserves on undrilled acreage were limited to those that are reasonably certain of production when drilled where we can verify the continuity of the reservoir. We only include wells in our proved undeveloped reserves that we currently plan to drill and in which we have adequate capital resources to enable us to drill them. Using empirical evidence, we utilize control points and sample sizes to show continuity in the reservoir. We reflect changes to undeveloped reserves that occur in the same field as revisions to the extent that proved undeveloped locations are revised due to changes in future development plans, including changes to proposed lateral lengths, development spacing and timing of development.

As of December 31, 2018, our proved undeveloped reserves were comprised of 2.1 million barrels of oil and 1.7 Tcf of natural gas. We had proved undeveloped oil reserves of 1.6 million barrels associated with our Eagle Ford shale properties and 0.5 million barrels associated with our Bakken shale properties. Most of our natural gas undeveloped reserves are associated with our Haynesville and Bossier shale properties where our drilling program in 2018 was focused. Our natural gas proved undeveloped reserves increased by 1.0 Tcf during 2018. This increase was primarily related to the reserve additions and performance related revisions which were comprised of 952 Bcf of new undeveloped locations resulting from our successful Haynesville and Bossier shale drilling program and expanded future drilling plans and 64 Bcf of upward performance revisions attributable to our Haynesville and Bossier shale undeveloped reserves added in prior years. Acquisitions during 2018 added 204 Bcf of natural gas. The reserve additions were partially offset by 129 Bcf of reserves converted to developed reserves and the divestiture of 74 Bcf of natural gas reserves. Twenty-three of the Haynesville shale wells we drilled in 2018 resulted in conversions of proved undeveloped reserves to proved developed producing reserves at December 31, 2018.

As of December 31, 2017, our proved undeveloped reserves were comprised of 681 Bcf of natural gas. All of our proved undeveloped reserves were associated with our Haynesville and Bossier shale properties where our 2017 drilling program was focused. Our natural gas proved undeveloped reserves increased by 130 Bcf during 2017. This increase was primarily related to the reserve additions which totaled 239 Bcf of natural gas, which were comprised of 220 Bcf of new undeveloped locations resulting from our successful Haynesville and Bossier shale drilling program and expanded future drilling plans and 19 Bcf of upward performance revisions attributable to our Haynesville and Bossier shale undeveloped reserves added in prior years. The reserve additions were partially offset by 104 Bcf of reserves converted to developed reserves. Eleven of the Haynesville shale wells we drilled in 2017 resulted in conversions of proved undeveloped reserves to proved developed producing reserves at December 31, 2017.

The following table presents the changes in our estimated proved undeveloped oil and natural gas reserves for the years ended December 31, 2016, 2017 and 2018:

	Proved Undeveloped Reserves					
	2016		2017		2018	
	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
Beginning Balance	—	258,466	—	550,941	—	680,842
Bakken Shale Contribution	—	—	—	—	502	1,061
Divestitures	—	—	—	(5,264)	(4,002)	(74,297)
Acquisitions	—	—	—	—	—	204,414
Extension & Discoveries	—	253,589	—	220,048	5,646	952,152
Conversions from Undeveloped to Developed	—	(55,338)	—	(103,506)	—	(128,692)
Price, Performance and Other Revisions	—	94,224	—	18,623	—	64,171
Total Change	—	292,475	—	129,901	2,146	1,018,809
Ending Balance	—	550,941	—	680,842	2,146	1,699,651

The timing, by year, when our proved undeveloped reserve quantities are estimated to be converted to proved developed reserves is as follows:

	Proved Undeveloped Reserves					
	2016		2017		2018	
Year ended December 31,	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
2017	—	101,024	—	—	—	—
2018	—	128,531	—	166,801	—	—
2019	—	121,611	—	140,953	966	214,481
2020	—	96,888	—	156,568	147	385,209
2021	—	102,887	—	119,640	378	487,265
2022	—	—	—	96,880	190	368,696
2023	—	—	—	—	465	244,000
Total	—	550,941	—	680,842	2,146	1,699,651

The following table presents the timing of our estimated future development capital costs to be incurred for the years ended December 31, 2016, 2017 and 2018:

Year ended December 31,	Future Development Costs Total Proved Undeveloped Reserves 2016	2017 (in millions)	2018
2017	$ 84.0	$ —	$ —
2018	89.3	149.1	—
2019	92.9	123.7	193.4
2020	74.6	138.4	364.3
2021	86.5	116.2	516.9
2022	—	89.9	431.6
2023	—	—	276.4
Total	$ 427.3	$ 617.3	$ 1,782.6

The following table presents the changes in our estimated future development costs for the years ended December 31, 2017 and 2018:

	(in millions)
Total as of December 31, 2016	$ 427.3
Development Costs Incurred	(93.4)
Asset Disposals	(2.3)
Additions and Revisions	285.7
Total Changes	190.0
Total as of December 31, 2017	617.3
Development Costs Incurred	(103.1)
Asset Disposals	(124.8)
Jones Contribution	9.2
Asset Acquisitions	184.1
Additions and Revisions	1,199.9
Total Changes	1,165.3
Total as of December 31, 2018	$ 1,782.6

Our estimated future capital costs to develop proved undeveloped reserves as of December 31, 2018 of $1.8 billion increased by $1.2 billion from our estimated future capital costs of $0.6 billion as of December 31, 2017. This increase was primarily attributable to the inclusion of 216 additional proved undeveloped Haynesville and Bossier shale locations at December 31, 2018. As of December 31, 2018, our future capital costs include $1.7 billion to develop our Haynesville/Bossier shale properties and $53.2 million to develop our oil properties in the Eagle Ford shale and the Bakken shale.

We incurred approximately $93.4 million during 2017 in development costs related to proved undeveloped reserves. Our estimated future capital costs to develop proved undeveloped reserves as of December 31, 2017 of $617.3 million increased by $190.0 million from our estimated future capital costs of $427.3 million as of December 31, 2016. This increase was primarily attributable to the inclusion of 32 additional proved undeveloped locations at December 31, 2017.

The estimates of our oil and natural gas reserves were determined by Lee Keeling and Associates, Inc. ("Lee Keeling"), an independent petroleum engineering firm. Lee Keeling has been providing consulting engineering and geological services for over fifty years. Lee Keeling's professional staff is comprised of qualified petroleum engineers who are experienced in all productive areas of the United States. The technical person responsible for review of our reserve estimates at Lee Keeling meets the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the

Standards Pertaining to Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Lee Keeling does not own any interests in our properties and is not employed on a contingent fee basis.

We have established, and maintain, internal controls designed to provide reasonable assurance that the estimates of proved reserves are computed and reported in accordance with rules and regulations promulgated by the SEC. These internal controls include documented process workflows, employing qualified professional engineering and geological personnel, and on-going education for personnel involved in our reserves estimation process. Our internal audit function routinely tests our processes and controls. Inputs to our reserves estimation process, which we provide to Lee Keeling for use in their reserves evaluation, are based upon our historical results for production history, oil and natural gas prices, lifting and development costs, ownership interests and other required data. Our Reservoir Engineering Department, comprised of qualified petroleum engineers and technical support staff, works with our operating, accounting, land and marketing departments in order to accumulate the information required for the reserves estimation process. Our Vice President of Reservoir Engineering is the primary person in charge of overseeing our reserve estimates and our Reservoir Engineering Department. He has a B.S. Degree and a Masters Degree in Petroleum Engineering, is a Registered Professional Engineer and has over forty years of experience in various technical roles within the oil and gas industry. During the reserves estimation process our petroleum engineers work with Lee Keeling to ensure that all data we provide is properly reflected in the final reserves estimates and they consult with Lee Keeling throughout the reserves estimation process on technical questions regarding the reserve estimates. We also regularly communicate with Lee Keeling throughout the year about our operations and the potential impact of operational changes and events on our reserve estimates.

We did not provide estimates of total proved oil and natural gas reserves during the three year period ended December 31, 2018 to any federal authority or agency, other than the SEC.

Drilling Activity Summary

During the three-year period ended December 31, 2018, we drilled development and exploratory wells as set forth in the table below:

	2016		2017		2018	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Oil	2	0.1	—	—	—	—
Gas	11	7.8	30	15.7	49	17.0
Dry	—	—	—	—	—	—
	13	7.9	30	15.7	49	17.0
Exploratory:						
Oil	—	—	—	—	—	—
Gas	—	—	—	—	—	—
Dry	—	—	—	—	—	—
	—	—	—	—	—	—
Total	13	7.9	30	15.7	49	17.0

In 2019 to the date of this report, we have drilled five wells (3.3 net to us) and we have seven wells (5.1 net to us) currently in the process of being drilled.

Producing Well Summary

The following table sets forth the gross and net producing oil and natural gas wells in which we owned an interest at December 31, 2018:

	Oil		Natural Gas	
	Gross	Net	Gross	Net
Louisiana	16	4.2	533	265.9
Mississippi	2	1.0	—	—
Montana	1	0.2	—	—
New Mexico	1	—	90	13.8
North Dakota	423	65.6	—	—
Oklahoma	6	0.6	99	8.9
Texas	11	2.5	418	271.2
Wyoming	—	—	26	1.9
Total	460	74.1	1,166	561.7

We operate 608 of the 1,626 producing wells presented in the above table. As of December 31, 2018, we did not own an interest in any wells containing multiple completions, which means that a well is producing from more than one completed zone.

Acreage

The following table summarizes our developed and undeveloped leasehold acreage at December 31, 2018, all of which is onshore in the continental United States. We have excluded acreage in which our interest is limited to a royalty or overriding royalty interest.

	Developed		Undeveloped	
	Gross	Net	Gross	Net
Louisiana	113,307	72,409	9,830	6,158
Mississippi	2,016	1,944	737	47
New Mexico	12,757	2,740	—	—
Oklahoma	26,080	3,382	—	—
Texas	50,668	28,125	33,095	19,373
Wyoming	13,440	927	—	—
Total	218,268	109,527	43,662	25,578

In addition to the acreage above, we have the right to earn interests in 2,829 (1,058 net to us) acres in Louisiana under the terms of a joint development venture.

Our undeveloped acreage expires as follows:

Expires in 2019	—%
Expires in 2020	5%
Expires in 2021	3%
Thereafter	92%
	100%

Title to our oil and natural gas properties is subject to royalty, overriding royalty, carried and other similar interests and contractual arrangements customary in the oil and gas industry, liens incident to operating agreements and for current taxes not yet due and other minor encumbrances. All of our oil and natural gas properties are pledged as collateral under our secured notes and our bank credit facility. As is customary in the oil and natural gas industry, we are generally able to retain our ownership interest in undeveloped acreage by production of existing wells, by drilling activity which establishes commercial reserves sufficient to maintain the lease, by payment of delay rentals or by the exercise of contractual extension rights.

Markets and Customers

The market for our production of oil and natural gas depends on factors beyond our control, including the extent of domestic production and imports of oil and natural gas, the proximity and capacity of natural gas pipelines and other transportation facilities, demand for oil and natural gas, the marketing of competitive fuels and the effects of state and federal regulation. The oil and gas industry also competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers.

Our oil production is currently sold under short-term contracts with a duration of six months or less. The contracts require the purchasers to purchase the amount of oil production that is available at prices tied to the spot oil markets. Our natural gas production is primarily sold under contracts with various terms and priced on first of the month index prices or on daily spot market prices. Approximately 47% of our 2018 natural gas sales were priced utilizing first of the month index prices and approximately 53% were priced utilizing daily spot prices. CIMA Energy, BP Energy Company and its subsidiaries, and Shell Oil Company and its subsidiaries accounted for 26%, 23%, and 19%, respectively, of our total 2018 sales. The loss of any of these customers would not have a material adverse effect on us as there is an available market for our crude oil and natural gas production from other purchasers.

We have entered into longer term marketing arrangements to ensure that we have adequate transportation to get our natural gas production in North Louisiana to the markets. As an alternative to constructing our own gathering and treating facilities, we have entered into a variety of gathering and treating agreements with midstream companies to transport our natural gas to the long-haul natural gas pipelines. We have entered into an agreement with a major natural gas marketing company to provide us with firm transportation for 10,000 MMBtu per day for our North Louisiana natural gas production on the long-haul pipelines. This agreement expires in 2019. To the extent we are not able to deliver the contracted natural gas volumes, we may be responsible for the transportation costs. Our production available to deliver under these agreements in North Louisiana is expected to exceed the firm transportation arrangements we have in place. In addition, the marketing company managing the firm transportation is required to use reasonable efforts to supplement our deliveries should we have a shortfall during the term of the agreements.

Competition

The oil and gas industry is highly competitive. Competitors include major oil companies, other independent energy companies and individual producers and operators, many of which have financial resources, personnel and facilities substantially greater than we do. We face intense competition for the acquisition of oil and natural gas properties and leases for oil and gas exploration.

Regulation

General. Various aspects of our oil and natural gas operations are subject to extensive and continually changing regulation, as legislation affecting the oil and natural gas industry is under constant review for amendment or expansion. Numerous departments and agencies, both federal and state, are authorized by statute to issue, and have issued, rules and regulations binding upon the oil and natural gas industry and its individual members. The Federal Energy Regulatory Commission, or "FERC", regulates the transportation and sale for resale of natural gas in interstate commerce pursuant to the Natural Gas Act of 1938, or "NGA", and the Natural Gas Policy Act of 1978, or "NGPA". In 1989, however, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining price and nonprice controls affecting all "first sales" of natural gas, effective January 1, 1993, subject to the terms of any private contracts that may be in effect. While sales by producers of natural gas and all sales of crude oil, condensate and natural gas liquids can currently be made at uncontrolled market prices, in the future Congress could reenact price controls or enact other legislation with detrimental impact on many aspects of our business. Under the provisions of the Energy Policy Act of 2005 (the "2005 Act"), the NGA has been amended to prohibit any form of market manipulation with the purchase or sale of natural gas, and the FERC has issued new regulations that are intended to increase natural gas pricing transparency. The 2005 Act has also significantly increased the penalties for violations of the NGA. The FERC has issued Order No. 704 et al. which requires a market participant to make an annual filing if it has sales or purchases equal to or greater than 2.2 million MMBtu in the reporting year to facilitate price transparency.

Regulation and transportation of natural gas. Our sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms for access to pipeline transportation are subject to extensive regulation. The FERC requires interstate pipelines to provide open-access transportation on a not unduly discriminatory basis for similarly situated shippers. The FERC frequently reviews and modifies its regulations regarding the transportation of natural gas, with the stated goal of fostering competition within the natural gas industry.

Intrastate natural gas transportation is subject to regulation by state regulatory agencies. The Texas Railroad Commission has been changing its regulations governing transportation and gathering services provided by intrastate pipelines and gatherers. While the changes by these state regulators affect us only indirectly, they are intended to further enhance competition in natural gas markets. We cannot predict what further action the FERC or state regulators will take on these matters; however, we do not believe that we will be affected differently in any material respect than other natural gas producers with which we compete by any action taken.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC, state commissions and the courts. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach pursued by the FERC, Congress and state regulatory authorities will continue.

Federal leases. Some of our operations are located on federal oil and natural gas leases that are administered by the Bureau of Land Management ("BLM") of the United States Department of the Interior. These leases are issued through competitive bidding and contain relatively standardized terms. These leases require compliance with detailed Department of Interior and BLM regulations and orders that are subject to interpretation and change. These leases are also subject to certain regulations and orders promulgated by the Department of Interior's Bureau of Ocean Energy Management, Regulation & Enforcement ("BOEMRE"), through its Minerals Revenue Management Program, which is responsible for the management of revenues from both onshore and offshore leases.

Oil and natural gas liquids transportation rates. Our sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at market prices. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act. In other instances, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to regulation by state regulatory bodies under state statutes. The price received from the sale of these products may be affected by the cost of transporting the products to market.

The FERC's regulation of pipelines that transport crude oil, condensate and natural gas liquids under the Interstate Commerce Act is generally more light-handed than the FERC's regulation of natural gas pipelines under the NGA. FERC-regulated pipelines that transport crude oil, condensate and natural gas liquids are subject to common carrier obligations that generally ensure non-discriminatory access. With respect to interstate pipeline transportation subject to regulation of the FERC under the Interstate Commerce Act, rates generally must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates are permitted in certain circumstances. Effective January 1, 1995, the

FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates governed by the Interstate Commerce Act that allowed for an increase or decrease in the transportation rates. The FERC's regulations include a methodology for such pipelines to change their rates through the use of an index system that establishes ceiling levels for such rates. The mandatory five year review in 2005 revised the methodology for this index to be based on Producer Price Index for Finished Goods (PPI-FG) plus 1.3 percent for the period July 1, 2006 through June 30, 2011. The mandatory five year review in 2012 revised the methodology for this index to be based on PPI-FG plus 2.65 percent for the period July 1, 2011 through June 30, 2016. The regulations provide that each year the Commission will publish the oil pipeline index after the PPI-FG becomes available.

With respect to intrastate crude oil, condensate and natural gas liquids pipelines subject to the jurisdiction of state agencies, such state regulation is generally less rigorous than the regulation of interstate pipelines. State agencies have generally not investigated or challenged existing or proposed rates in the absence of shipper complaints or protests. Complaints or protests have been infrequent and are usually resolved informally.

We do not believe that the regulatory decisions or activities relating to interstate or intrastate crude oil, condensate or natural gas liquids pipelines will affect us in a way that materially differs from the way it affects other crude oil, condensate and natural gas liquids producers or marketers.

Environmental regulations. We are subject to stringent federal, state and local laws. These laws, among other things, govern the issuance of permits to conduct exploration, drilling and production operations, the amounts and types of materials that may be released into the environment, the discharge and disposition of waste materials, the remediation of contaminated sites and the reclamation and abandonment of wells, sites and facilities. Numerous governmental departments issue rules and regulations to implement and enforce such laws, which are often difficult and costly to comply with and which carry substantial civil and even criminal penalties for failure to comply. Some laws, rules and regulations relating to protection of the environment may, in certain circumstances, impose strict liability for environmental contamination, rendering a person liable for environmental damages and cleanup cost without regard to negligence or fault on the part of such person. Other laws, rules and regulations may restrict the rate of oil and natural gas production below the rate that would otherwise exist or even prohibit exploration and production activities in sensitive areas. In addition, state laws often require various forms of remedial action to prevent pollution, such as closure of inactive pits and plugging of abandoned wells. The regulatory burden on the oil and natural gas industry increases our cost of doing business and consequently affects our profitability. These costs are considered a normal, recurring cost of our on-going operations. Our domestic competitors are generally subject to the same laws and regulations.

We believe that we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on our operations. Environmental laws and regulations have been subject to frequent changes over the years, and the imposition of more stringent requirements or new regulatory schemes such as carbon "cap and trade" programs could have a material adverse effect upon our capital expenditures, earnings or competitive position, including the suspension or cessation of operations in affected areas. The Trump Administration and Congress have made some changes and are expected to make additional changes to laws, regulations, and policies applicable to us. Executive Order 13783 directs federal agencies to review actions that potentially burden the development or use of domestically produced energy resources, and as a result, more regulatory changes are expected. Those changes may be favorable, but we are unable to predict the scope, timing, or impacts of such changes. There are also costs associated with responding to changing regulations and policies, whether such regulations are more or less stringent. As such, there can be no assurance that material cost and liabilities will not be incurred in the future.

The Comprehensive Environmental Response, Compensation and Liability Act; or "CERCLA", imposes 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 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. Under CERCLA, such persons may be subject to joint and several liability for the cost of investigating and cleaning up hazardous substances that have been released into the environment, for damages to natural resources and for the cost of certain health studies. In addition, companies that incur liability frequently also confront third party claims because 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 from a polluted site.

The Federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, or "RCRA", regulates the generation, transportation, storage, treatment and disposal of hazardous wastes and can require cleanup of hazardous waste disposal sites. RCRA currently excludes drilling fluids, produced waters and other wastes associated with the exploration, development or production of oil and natural gas from regulation as "hazardous waste". Disposal of such non-hazardous oil and natural gas exploration, development and production wastes usually are regulated by state law. Other wastes handled at exploration and production sites or used in the course of providing well services may not fall within this exclusion. Moreover, stricter standards for waste handling and disposal may be imposed on the oil and natural gas industry in the future. From time to time, legislation is proposed in Congress that would revoke or alter the current exclusion of exploration, development and production wastes from RCRA's definition of "hazardous wastes", thereby potentially subjecting such wastes to more stringent handling, disposal and cleanup requirements. If such legislation were enacted, it could have a significant impact on our operating costs, as well as the oil and natural gas industry in general. The impact of future revisions to environmental laws and regulations cannot be predicted.

Certain oil and gas wastes may also contain naturally occurring radioactive materials ("NORM"), which is regulated by the federal Occupational Safety and Health Administration and state agencies. These regulations require certain worker protections and waste handling and disposal procedures. We believe our operations comply in all material respects with these worker protection and waste handling and disposal requirements.

Our operations are also subject to the Clean Air Act, or "CAA", and comparable state and local requirements. Amendments to the CAA were adopted in 1990 and contain provisions that may result in the gradual imposition of certain pollution control requirements with respect to air emissions from our operations. On April 17, 2012, the U. S. Environmental Protection Agency or "EPA" promulgated new emission standards for the oil and gas industry. These rules require a nearly 95 percent reduction in volatile organic compounds ("VOCs") emitted from hydraulically fractured gas wells by January 1, 2015. This significant reduction in emissions is to be accomplished primarily through the use of "green completions" (i.e., capturing natural gas that currently escapes to the air). These rules also have notification and reporting requirements. In 2014, EPA revised the emission requirements for storage tanks emitting certain levels of VOCs requiring a 95% reduction of VOC emissions by April 15, 2014 and April 15, 2015 (depending upon the date of construction of the storage tank). In 2016, EPA finalized regulations that required further reductions specifically regarding methane emissions. However, on October 15, 2016, EPA proposed revisions to these finalized regulations with regard to certain emissions sources, including fugitive emission, pneumatic pumps, and closed vent systems. There are costs associated with following the status and impacts of these changes, and implementing any changes as they become effective. However, we believe our operations will not be materially adversely affected by any such requirements, and the requirements are not expected to be any more burdensome to us than to other similarly situated companies involved in oil and natural gas exploration and production activities.

The Federal Water Pollution Control Act of 1972, as amended, or the "Clean Water Act", imposes restrictions and controls on the discharge of produced waters and other wastes into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters and to conduct construction activities in waters and wetlands. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the oil and natural gas industry into certain coastal and offshore waters, unless otherwise authorized. Further, the EPA has adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans. The Clean Water Act and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges for oil and other pollutants and impose liability on parties responsible for those discharges for the cost of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. We believe that our operations comply in all material respects with the requirements of the Clean Water Act and state statutes enacted to control water pollution.

The Federal Safe Drinking Water Act of 1974, as amended, requires EPA to develop minimum federal requirements for Underground Injection Control ("UIC") programs and other safeguards to protect public health by preventing injection wells from contaminating underground sources of drinking water. The UIC program does not regulate wells that are solely used for production. However, EPA has authority to regulate hydraulic fracturing when diesel fuels are used in fluids or propping agents. In February 2014, EPA issued guidance on when UIC permitting requirements apply to fracking fluids containing diesel. We believe that our operations comply in all material respects with the requirements of the Federal Safe Drinking Water Act and similar state statutes. We believe the requirements are not any more burdensome to us than to other similarly situated companies involved in oil and natural gas exploration and production activities.

State and federal regulatory agencies recently have focused on a possible connection between the hydraulic fracturing related activities and the increased occurrence of seismic activity. When caused by human activity, such events are called induced seismicity. In a few instances, operators of injection wells in the vicinity of seismic events have been ordered to reduce injection volumes or suspend operations. Some state regulatory agencies, including those in Colorado, Ohio, Oklahoma, and Texas, have modified their regulations to account for induced seismicity. Regulatory agencies at all levels are continuing to study the possible linkage between oil and gas activity and induced seismicity. A 2012 report published by the National Academy of Sciences concluded that only a very small fraction of the tens of thousands of injection wells have been suspected to be, or have been, the likely cause of induced seismicity; and a 2015 report by researchers at the University of Texas has suggested that the link between seismic activity and wastewater disposal may vary by region. In 2015, the United States Geological Survey identified eight states, including Texas, with areas of increased rates of induced seismicity that could be attributed to fluid injection or oil and gas extraction. More recently, in March 2016, the United States Geological Survey identified six states with the most significant hazards from induced seismicity, including Texas, Colorado, Oklahoma, Kansas, New Mexico, and Arkansas. In addition, a number of lawsuits have been filed, most recently in Oklahoma, alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. Also, the EPA may develop rules to specifically address the disposal of wastewater from oil and gas development and the potential for induced seismicity from wastewater injection. These developments could result in additional regulation and restrictions on the use of injection wells and hydraulic fracturing.

In December 2016, the EPA finalized its report on the potential impacts of hydraulic fracturing on drinking water resources, which concluded that hydraulic fracturing activities could impact drinking water resources under some circumstances. Other governmental agencies, including the U.S. Department of Energy, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies have the potential to impact the likelihood or scope of future legislation or regulation.

Federal regulators require certain owners or operators of facilities that store or otherwise handle oil to prepare and implement spill prevention, control, countermeasure and response plans relating to the possible discharge of oil into surface waters. The Oil Pollution Act of 1990 ("OPA") contains numerous requirements relating to the prevention and response to oil spills in the waters of the United States. The OPA subjects owners of facilities to strict joint and several liability for all containment and cleanup costs and certain other damages relating to a spill. Noncompliance with OPA may result in varying civil and criminal penalties and liabilities.

Executive Order 13158, issued on May 26, 2000, directs federal agencies to safeguard existing Marine Protected Areas, or MPAs, in the United States and establish new MPAs. The order requires federal agencies to avoid harm to MPAs to the extent permitted by law and to the maximum extent practicable. It also directs the EPA to propose new regulations under the Clean Water Act to ensure appropriate levels of protection for the marine environment. This order has the potential to adversely affect our operations by restricting areas in which we may carry out future exploration and development projects and/or causing us to incur increased operating expenses.

Certain flora and fauna that have officially been classified as "threatened" or "endangered" are protected by the Endangered Species Act. This law prohibits any activities that could "take" a protected plant or animal or reduce or degrade its habitat area. If endangered species are located in an area we wish to develop, the work could be prohibited or delayed and/or expensive mitigation might be required.

Other statutes that provide protection to animal and plant species and which may apply to our operations include, but are not necessarily limited to, the Oil Pollution Act, the Emergency Planning and Community Right to Know Act, the Marine Mammal Protection Act, the Marine Protection, Research and Sanctuaries Act, the Fish and Wildlife Coordination Act, the Fishery Conservation and Management Act, the Migratory Bird Treaty Act and the National Historic Preservation Act. These laws and regulations may require the acquisition of a permit or other authorization before construction or drilling commences and may limit or prohibit construction, drilling and other activities on certain lands lying within wilderness or wetlands and other protected areas and impose substantial liabilities for pollution resulting from our operations. The permits required for our various operations are subject to revocation, modification and renewal by issuing authorities. In addition, laws such as the National Environmental Policy Act and the Coastal Zone Management Act may make the process of obtaining certain permits more difficult or time consuming, resulting in increased costs and potential delays that could affect the viability or profitability of certain activities. Administrative policies with respect to such laws are also changing, and we incur costs to follow such changes and comply as changes become effective.

Certain statutes such as the Emergency Planning and Community Right to Know Act require the reporting of hazardous chemicals manufactured, processed, or otherwise used, which may lead to heightened scrutiny of the company's operations by regulatory agencies or the public. In 2012, the EPA adopted a new reporting requirement, the Petroleum and Natural Gas Systems Greenhouse Gas Reporting Rule (40 C.F.R. Part 98, Subpart W), which requires certain onshore petroleum and natural gas facilities to begin collecting data on their emissions of greenhouse gases, or GHGs, in January 2012, with the first annual reports of those emissions due on September 28, 2012. GHGs include gases such as methane, a primary component of natural gas, and carbon dioxide, a byproduct of burning natural gas. Different GHGs have different global warming potentials with CO2 having the lowest global warming potential, so emissions of GHGs are typically expressed in terms of CO2 equivalents, or CO2e. The rule applies to facilities that emit 25,000 metric tons of CO2e or more per year, and requires onshore petroleum and natural gas operators to group all equipment under common ownership or control within a single hydrocarbon basin together when determining if the threshold is met. These greenhouse gas reporting rules were amended on October 22, 2015 to expand the number of sources and operations that are subject to these rules, and again on November 18, 2016 to provide less burdensome reporting requirements. We have determined that these reporting requirements apply to us and we believe we have met all of the EPA required reporting deadlines and strive to ensure accurate and consistent emissions data reporting. It is possible that these requirements may be loosened or otherwise changed in the future. Other EPA actions with respect to the reduction of greenhouse gases (such as EPA's Greenhouse Gas Endangerment Finding, and EPA's Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule) and various state actions have or could impose mandatory reductions in greenhouse gas emissions. We are unable to predict at this time how much the cost of compliance with any legislation or regulation of greenhouse gas emissions will be in future periods.

The U.S. has not passed legislation to expressly address GHGs; however, in recent years the EPA moved ahead with its efforts to regulate GHG emissions from certain sources by rule. Beyond requiring measurement and reporting of GHGs as discussed above, the EPA 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 EPA has adopted regulations that would require permits for and reductions in greenhouse gas emissions for certain facilities. States in which we operate may also require permits and reductions in GHG emissions. Additionally, the EPA published a set of final rules in 2016 that require reductions in VOC and methane generation from new sources, and EPA has announced plans to issue rules regulating existing sources. However, these rules have been challenged in court, and in 2017, the EPA took steps to institute a two-year delay in implementing the rules. In 2018, EPA revised a portion of these rules and additional changes may still be forthcoming. Similarly, the Bureau of Land Management ("BLM") has proposed to suspend and revise a 2016 rule relating to methane venting, flaring, and leaks from oil and gas production on public lands that was being challenged by multiple western states and energy companies. On April 4, 2018, the Federal District Court in Wyoming issued an order staying the current litigation until BLM either finalizes a revised rule or withdraws it. Since all of our oil and natural gas production is in the United States, laws or regulations that have been or may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur substantial increased operating costs, and could have an adverse effect on demand for the oil and natural gas we produce. In addition, efforts have been made and continue to be made in the international community toward the adoption of international treaties or protocols that would address global climate change issues. Most recently in 2015, the United States participated in the United Nations Conference on Climate Change, which led to the creation of the Paris Agreement. The Paris Agreement requires ratifying countries to review and "represent a progression" in the ambitions of their nationally determined contributions, which set GHG emission reduction goals, every five years. The United States signed the Paris Agreement on April 22, 2016; however, the Trump Administration has stated that it intends to withdraw from the Paris Agreement. The Agreement allows for the U.S. to formally announce its intention to withdraw in November 2019 with the withdrawal effective in November 2020. Considering the extended timeline for this action, impacts to our operations are uncertain; however, we expect that the impacts to our operations will not be materially different from other similarly situated companies involved in oil and natural gas exploration and production activities.

In 2010 the BLM began implementation of a proposed oil and gas leasing reform that would increase environmental review requirements and was expected to have the effect of reducing the amount of new federal lands made available for lease, increasing the competition for and cost of available parcels. This leasing reform initiative was replaced by a new BLM policy, dated January 31, 2018, which is expected to remove the additional environmental review created under the 2010 initiative and streamline the leasing process. Additionally, on December 28, 2017, the BLM rescinded a rule the BLM adopted in 2015 concerning hydraulic fracturing on federal land. The 2015 rule would have required increased well integrity testing, increased requirements for the managing of fluids, and the disclosure of chemicals used in fracturing. Due to the ongoing regulatory and legal uncertainty, we cannot predict what effect these changes will have on our operations, though the changes may be advantageous. We expect that the impacts to our operations will be similar to other similarly situated companies involved in oil and natural gas exploration and production activities.

Such changes in environmental laws and regulations which result in more stringent and costly reporting, or waste handling, storage, transportation, disposal or cleanup activities, could materially affect companies operating in the energy industry. Adoption of new regulations further regulating emissions from oil and gas production could adversely affect our business, financial position, results of operations and prospects, as could the adoption of new laws or regulations which levy taxes or other costs on greenhouse gas emissions from other industries, which could result in changes to the consumption and demand for natural gas. We may also be assessed administrative, civil and/or criminal penalties if we fail to comply with any such new laws and regulations applicable to oil and natural gas production.

Regulation of oil and natural gas exploration and production. Our exploration and production operations are subject to various types of regulation at the federal, state and local levels. Such regulations include requiring permits and drilling bonds for the drilling of wells, regulating the location of wells, the method of drilling and casing wells and the surface use and restoration of properties upon which wells are drilled. Many states also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and natural gas wells and the regulation of spacing, plugging and abandonment of such wells. Some state statutes limit the rate at which oil and natural gas can be produced from our properties. It is also possible that certain states may increase regulatory activity in response to changing federal regulations or policies.

State regulation. Most states regulate the production and sale of oil and natural gas, including requirements for obtaining drilling permits, the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and gas resources. The rate of production may be regulated and the maximum daily production allowable from both oil and gas wells may be established on a market demand or conservation basis or both.

Office and Operations Facilities

Our executive offices are located at 5300 Town and Country Blvd., Suite 500 in Frisco, Texas 75034 and our telephone number is (972) 668-8800. We lease office space in Frisco, Texas covering 66,382 square feet at a monthly rate of $129,998. This lease expires on December 31, 2021. We also own production offices and pipe yard facilities near Carthage and Marshall, Texas and Homer and Logansport, Louisiana.

Employees

As of December 31, 2018, we had 113 employees and utilized contract employees for certain of our field operations. We consider our employee relations to be satisfactory.

Directors and Executive Officers

The following table sets forth certain information concerning our executive officers and directors.

Name	Position with Company	Age
M. Jay Allison	Chief Executive Officer and Chairman of the Board of Directors	63
Roland O. Burns	President, Chief Financial Officer, Secretary and Director	58
Daniel S. Harrison	Vice President of Operations	55
Michael D. McBurney	Vice President of Marketing	63
Daniel K. Presley	Vice President of Accounting, Controller and Treasurer	58
Russell W. Romoser	Vice President of Reservoir Engineering	67
LaRae L. Sanders	Vice President of Land	56
Richard D. Singer	Vice President of Financial Reporting	64
Blaine M. Stribling	Vice President of Corporate Development	47
Elizabeth B. Davis	Director	56
Morris E. Foster	Director	75
Jim L. Turner	Director	73

A brief biography of each person who serves as an executive officer or director follows below.

Executive Officers

M. Jay Allison has been our Chief Executive Officer since 1988. Mr. Allison was elected Chairman of the Board in 1997 and has been a director since 1987. From 1988 to 2013, Mr. Allison served as our President. From 1981 to 1987, he was a practicing oil and gas attorney with the firm of Lynch, Chappell & Alsup in Midland, Texas. He received B.B.A., M.S. and J.D. degrees from Baylor University in 1978, 1980 and 1981, respectively. Mr. Allison presently serves on the Board of Regents for Baylor University.

Roland O. Burns has been our President since 2013, Chief Financial Officer since 1990, Secretary since 1991 and a director since 1999. Mr. Burns served as our Senior Vice President from 1994 to 2013 and Treasurer from 1990 to 2013. From 1982 to 1990, Mr. Burns was employed by the public accounting firm, Arthur Andersen. During his tenure with Arthur Andersen, Mr. Burns worked primarily in the firm's oil and gas audit practice. Mr. Burns received B.A. and M.A. degrees from the University of Mississippi in 1982 and is a Certified Public Accountant. Mr. Burns also serves on the Board of Directors of the Cotton Bowl Athletic Association and the University of Mississippi Foundation.

Daniel S. Harrison has been our Vice President of Operations since 2017. Mr. Harrison has been with us since 2008 and served in various engineering and operations management positions of increasing responsibility during that time. Prior to joining us, Mr. Harrison was an operations engineer at Cimarex Energy Company from 2005 to 2008. Prior to 2005 he worked in various petroleum engineering operations management positions for several independent oil and gas exploration and development companies. Mr. Harrison received a B.S. Degree in Petroleum Engineering from the Louisiana State University in 1985.

Michael D. McBurney has been our Vice President of Marketing since 2013. Mr. McBurney has over 34 years of energy industry experience within the oil, natural gas, LNG, and power segments. Prior to joining us, Mr. McBurney worked for EXCO Resources, Inc., an independent exploration and production company where he was responsible for natural gas and natural gas liquids marketing. From 2000 to 2006, Mr. McBurney was with FPL Energy of Florida, where he was responsible for Fuel and Transportation logistics for large scale power generation facilities located throughout the U.S. Mr. McBurney received a B.B.A. in Finance from the University of North Texas in 1978.

Daniel K. Presley has been our Treasurer since 2013. Mr. Presley, who has been with us since 1989, also continues to serve as our Vice President of Accounting and Controller, positions he has had held since 1997 and 1991, respectively. Prior to joining us, Mr. Presley had six years of experience with several independent oil and gas companies including AmBrit Energy, Inc. Prior thereto, Mr. Presley spent two and one-half years with B.D.O. Seidman, a public accounting firm. Mr. Presley received a B.B.A. degree from Texas A & M University in 1983.

Russell W. Romoser has been our Vice President of Reservoir Engineering since 2012. Mr. Romoser has over 40 years of experience as a reservoir engineer both with industry and with a petroleum engineering consulting firm. Prior to joining us, Mr. Romoser served eleven years as the Acquisitions Engineering Manager for EXCO Resources, Inc. Mr. Romoser received a B.S. Degree in Petroleum Engineering in 1975 and a Masters Degree in Petroleum Engineering in 1976 from the University of Texas and is a Registered Professional Engineer in Oklahoma and Texas.

LaRae L. Sanders has been our Vice President of Land since 2014. Ms. Sanders has been with us since 1995. She has served as Land Manager since 2007, and has been instrumental in all of our active development programs and major acquisitions. Prior to joining us, Ms. Sanders held positions with Bridge Oil Company and Kaiser-Francis Oil Company, as well as other independent exploration and production companies. Ms. Sanders is a Certified Professional Landman with 36 years of experience. She became the nation's first Certified Professional Lease and Title Analyst in 1990.

Richard D. Singer has been our Vice President of Financial Reporting since 2005. Mr. Singer has over 40 years of experience in financial accounting and reporting. Prior to joining us, Mr. Singer most recently served as an assistant controller for Holly Corporation from 2004 to 2005 and as assistant controller for Santa Fe International Corporation from 1988 to 2002. Mr. Singer received a B.S. degree from the Pennsylvania State University in 1976 and is a Certified Public Accountant.

Blaine M. Stribling has been our Vice President of Corporate Development since 2012. From 2007 to 2012, Mr. Stribling served as our Asset & Corporate Development Manager. Prior to joining us, Mr. Stribling managed a development project team at Encana Oil & Gas from 2005 to 2007. Prior to 2005 he worked in various petroleum engineering operations management positions of increasing responsibility for several independent oil and gas exploration and development companies. Mr. Stribling received a B.S. Degree in Petroleum Engineering from the Colorado School of Mines.

Outside Directors

Elizabeth B. Davis has served as a director since 2014. Dr. Davis is currently the President of Furman University. Dr. Davis was the Executive Vice President and Provost for Baylor University until July 2014, and served as Interim Provost from 2008 until 2010. Prior to her appointment as Provost, she was a professor of accounting in the Hankamer School of Business at Baylor University where she also served as associate dean for undergraduate programs and as acting chair for the Department of Accounting and Business Law. Prior to joining Baylor University, she worked for the public accounting firm Arthur Andersen from 1984 to 1987.

Morris E. Foster has served as a director since 2017. Mr. Morris retired in 2008 as Vice President of ExxonMobil Corporation and President of ExxonMobil Production Company following more than 40 years of service with the ExxonMobil group. Mr. Foster served in a number of production engineering and management roles domestically as well as in the United Kingdom and Malaysia prior to his appointment in 1995 as a Senior Vice President in charge of the upstream business of Exxon Company, USA. In 1998, Mr. Foster was appointed President of Exxon Upstream Development Company, and following the merger of Exxon and Mobil in 1999, he was named to the position of President of ExxonMobil Development Company. In 2004, Mr. Foster was named President of Exxon Mobil Production Company, the division responsible for ExxonMobil's upstream oil and gas exploration and production business, and a Vice President of ExxonMobil Corporation. Mr. Foster currently serves as Chairman of Stagecoach Properties Inc., a real estate holding corporation with properties in Salado, Houston and College Station, Texas and Carmel, California and as a member of the Board of Regents of Texas A&M University. In addition, Mr. Foster currently serves on the board of directors of Scott & White Medical Institute and First State Bank of Temple, Texas.

Jim L. Turner has served as a director since 2014. Mr. Turner currently serves as principal of JLT Beverages, L.P., a position he has held since 1996. Mr. Turner is also Chief Executive Officer of JLT Automotive, Inc. Mr. Turner served as President and Chief Executive Officer of Dr. Pepper/Seven Up Bottling Group, Inc., from its formation in 1999 through 2005, when he sold his interest in that company. Prior to that, Mr. Turner served as Owner/Chairman of the Board and Chief Executive Officer of the Turner Beverage Group, the largest privately owned independent bottler in the United States. Mr. Turner currently serves as a non-executive chairman of the board of directors for Dean Foods Company and is past chairman and currently serves on the board of trustees of Baylor Scott and White Health, the largest not-for-profit healthcare system in the state of Texas. He is also a director of Crown Holdings, Inc. and INSURICA.

Available Information

Our executive offices are located at 5300 Town and Country Blvd., Suite 500, Frisco, Texas 75034. Our telephone number is (972) 668-8800. We file annual, quarterly and current reports, proxy statements and other documents with the SEC under the Securities Exchange Act of 1934. The SEC maintains a website that contains reports, proxy and information statements, and other information that is electronically filed with the SEC. The public can obtain any documents that we file with the SEC at www.sec.gov. We also make available free of charge on our website (www.comstockresources.com) our Annual Report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after we file such material with, or furnish it to, the SEC.

ITEM 1A. *RISK FACTORS*

You should carefully consider the following risk factors as well as the other information contained or incorporated by reference in this report, as these important factors, among others, could cause our actual results to differ from our expected or historical results. It is not possible to predict or identify all such factors. Consequently, you should not consider any such list to be a complete statement of all of our potential risks or uncertainties. Based on the information currently known to us, we believe the following information identifies the most significant risk factors affecting us, but the below risks and uncertainties are not the only ones related to our businesses and are not necessarily listed in the order of their significance. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also adversely affect our business

An extended period of depressed oil and natural gas prices will adversely affect our business, financial condition, cash flow, liquidity, results of operations and our ability to meet our capital expenditure obligations and financial commitments.

Our business is heavily dependent upon the prices of, and demand for, oil and natural gas. Historically, the prices for oil and natural gas have been volatile and are likely to remain volatile in the future. During 2018, commodity prices fluctuated significantly, with the settlement price for West Texas Intermediate ("WTI") crude oil ranging from a high of approximately $76.41 per barrel to a low of approximately $44.61 per barrel and settlement prices for Henry Hub natural gas ranging from a high of approximately $4.84 per Mcf to a low of approximately $2.56 per Mcf. Oil and natural gas price volatility continued into 2019 and, through March 1, 2019, the WTI settlement price of crude oil had a low of approximately $46.54 per barrel, and the Henry Hub settlement price of natural gas reached a low of approximately $2.55 per Mcf.

The prices we receive for our oil and natural gas production are subject to wide fluctuations and depend on numerous factors beyond our control, including the following:

- the domestic and foreign supply of oil, natural gas liquids and natural gas;
- weather conditions;
- the price and quantity of imports of oil and natural gas;
- political conditions and events in other oil-producing and natural gas-producing countries, including embargoes, hostilities in the Middle East and other sustained military campaigns, and acts of terrorism or sabotage;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC;
- domestic government regulation, legislation and policies;
- the level of global oil and natural gas inventories;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels; and
- overall economic conditions.

Lower oil and natural gas prices will adversely affect:

- our revenues, profitability and cash flow from operations;
- the value of our proved oil and natural gas reserves;
- the economic viability of certain of our drilling prospects;
- our borrowing capacity; and
- our ability to obtain additional capital.

Our debt service requirements could adversely affect our operations and limit our growth.

We had $1.3 billion principal amount of debt as of December 31, 2018.

Our outstanding debt has important consequences, including, without limitation:

- a portion of our cash flow from operations is required to make debt service payments;
- our ability to borrow additional amounts for capital expenditures (including acquisitions) or other purposes is limited; and
- our debt limits (i) our ability to capitalize on significant business opportunities, (ii) our flexibility in planning for or reacting to changes in market conditions, and (iii) our ability to withstand competitive pressures and economic downturns.

Future acquisitions or development activities may require us to alter our capitalization significantly. These changes in capitalization may significantly increase our debt. Moreover, our ability to meet our debt service obligations and to reduce our total debt will be dependent upon our future performance, which will be subject to general economic conditions and financial, business and other factors affecting our operations, many of which are beyond our control. If we are unable to service our indebtedness and to meet other commitments, we will be required to adopt one or more alternatives, such as refinancing or restructuring our indebtedness, selling material assets or seeking to raise additional debt or equity capital. We cannot assure you that any of these actions could be effected on a timely basis or on satisfactory terms or that these actions would enable us to continue to satisfy our capital requirements.

Our debt agreements contain a number of significant covenants. These covenants limit our ability to, among other things:

- borrow additional money;
- merge, consolidate or dispose of assets;
- make certain types of investments;
- enter into transactions with our affiliates; and
- pay dividends.

Our failure to comply with any of these covenants could cause a default under our bank credit facility and the indenture governing our outstanding notes. A default, if not waived, could result in acceleration of our indebtedness, in which case the debt would become immediately due and payable. If this occurs, we may not be able to repay our debt or borrow sufficient funds to refinance it given the current status of the credit markets. Even if new financing is available, it may not be on terms that are acceptable to us. Complying with these covenants may cause us to take actions that we otherwise would not take or not take actions that we otherwise would take.

Our access to capital markets may be limited in the future.

Adverse changes in the financial and credit markets could negatively impact our ability to grow production and reserves and meet our future obligations. In addition, the continuation of the current low oil and natural gas price environment, or further declines of oil and natural gas prices, will affect our ability to obtain financing for acquisitions and drilling activities and could result in a reduction in drilling activity, which could lead to a loss of acreage due to lease expirations, both of which could negatively affect our ability to replace reserves.

Our future production and revenues depend on our ability to replace our reserves.

Our future production and revenues depend upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Our proved reserves will generally decline as reserves are depleted, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves, or both. To increase reserves and production, we must continue our acquisition and drilling activities. We cannot assure you that we will have adequate capital resources to conduct acquisition and drilling activities or that our acquisition and drilling activities will result in significant additional reserves or that we will have continuing success drilling productive wells at low finding and development costs. Furthermore, while our revenues may increase if prevailing oil and natural gas prices increase significantly, our finding costs for additional reserves could also increase.

Prospects that we decide to drill may not yield oil or natural gas in commercially viable quantities or quantities sufficient to meet our targeted rate of return.

A prospect is a property in which we own an interest, or have operating rights to, and that has what our geoscientists believe, based on available seismic and geological information, to be an indication of potential oil or natural gas. Our prospects are in various stages of evaluation, ranging from a prospect that is ready to be drilled to a prospect that will require substantial additional evaluation and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. The analysis that we perform using data from other wells, more fully explored prospects and/or producing fields may not be useful in predicting the characteristics and potential reserves associated with our drilling prospects. If we drill additional unsuccessful wells, our drilling success rate may decline and we may not achieve our targeted rate of return.

Our business involves many uncertainties and operating risks that can prevent us from realizing profits and can cause substantial losses.

Our success depends on the success of our exploration and development activities. Exploration activities involve numerous risks, including the risk that no commercially productive natural gas or oil reserves will be discovered. In addition, these activities may be unsuccessful for many reasons, including weather, cost overruns, equipment shortages and mechanical difficulties. Moreover, the successful drilling of a natural gas or oil well does not ensure we will realize a profit on our investment. A variety of factors, both geological and market-related, can cause a well to become uneconomical or only marginally economical. In addition to their costs, unsuccessful wells can hurt our efforts to replace production and reserves.

Our business involves a variety of operating risks, including:

- unusual or unexpected geological formations;
- fires;
- explosions;
- blow-outs and surface cratering;
- uncontrollable flows of natural gas, oil and formation water;
- natural disasters, such as hurricanes, tropical storms and other adverse weather conditions;
- pipe, cement, or pipeline failures;
- casing collapses;
- mechanical difficulties, such as lost or stuck oil field drilling and service tools;
- abnormally pressured formations; and
- environmental hazards, such as natural gas leaks, oil spills, pipeline ruptures and discharges of toxic gases.

If we experience any of the above operating risks, our well bores, gathering systems and processing facilities could be affected, which could adversely affect our ability to conduct operations.

We could also incur substantial losses as a result of:

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

We maintain insurance against "sudden and accidental" occurrences, which may cover some, but not all, of the risks described above. Most significantly, the insurance we maintain will not cover the risks described above which occur over a sustained period of time. Further, there can be no assurance that such insurance will continue to be available to cover all such cost or that such insurance will be available at a cost that would justify its purchase. The occurrence of a significant event not fully insured or indemnified against could have a material adverse effect on our financial condition and results of operations.

We operate in a highly competitive industry, and our failure to remain competitive with our competitors, many of which have greater resources than we do, could adversely affect our results of operations.

The oil and natural gas industry is highly competitive in the search for and development and acquisition of reserves. Our competitors often include companies that have greater financial and personnel resources than we do. These resources could allow those competitors to price their products and services more aggressively than we can, which could hurt our profitability. Moreover, our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to close transactions in a highly competitive environment.

If oil and natural gas prices decline further or remain low for an extended period of time, we may be required to further write-down the carrying values and/or the estimates of total reserves of our oil and natural gas properties, which would constitute a non-cash charge to earnings and adversely affect our results of operations.

Accounting rules applicable to us require that we periodically review the carrying value of our oil and natural gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and natural gas properties. A write-down constitutes a non-cash charge to earnings. We recognized impairments that totaled $27.1 million and $44.0 million in 2016 and 2017, respectively, which reduced the carrying value of our oil and natural gas properties. We may incur additional non-cash charges in the future, which could have a material adverse effect on our results of operations in the period taken. We may also reduce our estimates of the reserves that may be economically recovered, which could have the effect of reducing the total value of our reserves.

Our reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

Reserve engineering is a subjective process of estimating the recovery from underground accumulations of oil and natural gas that cannot be precisely measured. The accuracy of any reserve estimate depends on the quality of available data, production history and engineering and geological interpretation and judgment. Because all reserve estimates are to some degree imprecise, the quantities of oil and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future oil and natural gas prices may all differ materially from those assumed in these estimates. The information regarding the present value of future net cash flows attributable to our proved oil and natural gas reserves is only an estimate and should not be construed as the current market value of the oil and natural gas reserves attributable to our properties. Thus, such information includes revisions of certain reserve estimates attributable to proved properties included in the preceding year's estimates. Such revisions reflect additional information from subsequent activities, production history of the properties involved and any adjustments in the projected economic life of such properties resulting from changes in product prices. Any future downward revisions could adversely affect our financial condition, our borrowing ability, our future prospects and the value of our common stock.

As of December 31, 2018, 71% of our total proved reserves were undeveloped and 2% were developed non-producing. These reserves may not ultimately be developed or produced. Furthermore, not all of our undeveloped or developed non-producing reserves may be ultimately produced at the time periods we have planned, at the costs we have budgeted, or at all. As a result, we may not find commercially viable quantities of oil and natural gas, which in turn may result in a material adverse effect on our results of operations.

Some of our undeveloped leasehold acreage is subject to leases that will expire unless production is established on units containing the acreage.

Leases on oil and gas properties normally have a term of three to five years and will expire unless, prior to expiration of the lease term, production in paying quantities is established. If the leases expire and we are unable to renew them, we will lose the right to develop the leased properties. Our drilling plans for these areas are subject to change based upon various factors, including drilling results, commodity 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.

We pursue acquisitions as part of our growth strategy and there are risks associated with such acquisitions.

Our growth has been attributable in part to acquisitions of producing properties and companies. More recently we have been focused on acquiring acreage for our drilling program. We expect to continue to evaluate and, where appropriate, pursue acquisition opportunities on terms we consider favorable. However, we cannot assure you that suitable acquisition candidates will be identified in the future, or that we will be able to finance such acquisitions on favorable terms. In addition, we compete against other companies for acquisitions, and we cannot assure you that we will successfully acquire any material property interests. Further, we cannot assure you that future acquisitions by us will be integrated successfully into our operations or will increase our profits.

The successful acquisition of producing properties requires an assessment of numerous factors beyond our control, including, without limitation:

- recoverable reserves;
- exploration potential;
- future oil and natural gas prices;
- operating costs; and
- potential environmental and other liabilities.

In connection with such assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. The resulting assessments are inexact and their accuracy uncertain, and such a review may not reveal all existing or potential problems, nor will it necessarily permit us to become sufficiently familiar with the properties to fully assess their merits and deficiencies. Inspections may not always be performed on every well, and structural and environmental problems are not necessarily observable even when an inspection is made.

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties, which may be substantially different in operating and geologic characteristics or geographic location than our existing properties. While our current operations are focused in Texas and Louisiana, we may pursue acquisitions or properties located in other geographic areas.

If we are unsuccessful at marketing our oil and natural gas at commercially acceptable prices, our profitability may decline.

Our ability to market oil and natural gas at commercially acceptable prices depends on, among other factors, the following:

- the availability and capacity of gathering systems and pipelines;
- federal and state regulation of production and transportation;
- changes in supply and demand; and
- general economic conditions.

Our inability to respond appropriately to changes in these factors could negatively affect our profitability.

Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and processing facilities. Our ability to market our production depends in a substantial part on the availability and capacity of gathering systems, pipelines and processing facilities, which, in some cases, may be owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells due to a lack of market demand or because of the inadequacy or unavailability of pipelines or gathering system capacity. If that were to occur, then we would be unable to realize revenue from those wells until arrangements were made to deliver our production to market.

We are subject to extensive governmental laws and regulations that may adversely affect the cost, manner or feasibility of doing business.

Our operations and facilities are subject to extensive federal, state and local laws and regulations relating to the exploration for, and the development, production and transportation of, oil and natural gas, as well as the safe operations thereof. Future laws or regulations, adverse changes in the interpretation of existing laws and regulations or our failure to comply with existing legal requirements may harm our business, results of operations and financial condition. We may be required to make large and unanticipated capital expenditures to comply with present and future governmental laws and regulations, such as:

- lease permit restrictions;
- drilling bonds and other financial responsibility requirements, such as plug and abandonment bonds;
- spacing of wells;
- unitization and pooling of properties;
- safety precautions;
- regulatory requirements; and
- taxation.

Under these laws and regulations, we could be liable for:

- personal injuries;
- property and natural resource damages;
- well reclamation costs; and
- governmental sanctions, such as fines and penalties.

Our operations could be significantly delayed or curtailed and our cost of operations could significantly increase as a result of regulatory requirements or restrictions. We are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations.

Our operations are substantially dependent on the availability of water. Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash flows.

Water is an essential component of both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from various sources for use in our operations. If we are unable to obtain water from local sources to use in our operations, we may be unable to economically produce oil and natural gas, which could have an adverse effect on our financial condition, results of operations and cash flows.

Our operations may incur substantial liabilities due to compliance with environmental laws and regulations.

Our oil and natural gas operations are subject to stringent federal, state and local laws and regulations relating to the release or disposal of materials into the environment and otherwise relating to environmental protection. These laws and regulations:

- require the acquisition of one or more permits before drilling commences;
- impose limitations on where drilling can occur and/or requires mitigation before authorizing drilling in certain locations;
- restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities;
- require reporting of significant releases, and annual reporting of the nature and quantity of emissions, discharges and other releases into the environment;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and
- impose substantial liabilities for pollution resulting from our operations.

Failure to comply with these laws and regulations may result in:

- the assessment of administrative, civil and criminal penalties;
- the incurrence of investigatory and/or remedial obligations; and
- the imposition of injunctive relief.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly restrictions on emissions, and/or waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to reach and maintain compliance and may otherwise have a material adverse effect on our industry in general and on our own results of operations, competitive position or financial condition. Under these environmental laws and regulations, we could be held strictly liable for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or contamination, even if our operations met previous industry standards at the time they were performed. Future environmental laws and regulations, including proposed legislation regulating GHGs or climate change, may negatively impact our industry. The costs of compliance with these requirements may have an adverse impact on our financial condition, results of operations and cash flows.

Our hedging transactions could result in financial losses or could reduce our income. To the extent we have hedged a significant portion of our expected production and our actual production is lower than we expected or the costs of goods and services increase, our profitability would be adversely affected.

To achieve more predictable cash flows and to reduce our exposure to adverse fluctuations in the prices of oil and gas, we have entered into and may continue to enter into hedging transactions for certain of our expected oil and natural gas production. These transactions could result in both realized and unrealized hedging losses. Further, these hedges may be inadequate to protect us from continuing and prolonged declines in the price of oil and natural gas. To the extent that the prices of oil and natural gas remain at current levels or declines further, we will not be able to hedge future production at the same level as our current hedges, and our results of operations and financial condition would be negatively impacted.

The extent of our commodity price exposure is related largely to the effectiveness and scope of our derivative activities. For example, the derivative instruments we utilize are primarily based on NYMEX futures prices, which may differ significantly from the actual crude oil and gas prices we realize in our operations. Furthermore, we have adopted a policy that requires, and our revolving credit facility also requires, that we enter into derivative transactions related to only a portion of our expected production volumes and, as a result, we will continue to have direct commodity price exposure on the portion of our production volumes not covered by these derivative financial instruments.

Our actual future production may be significantly higher or lower than we estimate at the time we enter into derivative transactions. If our actual future production is higher than we estimated, we will have greater commodity price exposure than we intended. If our actual future production is lower than the nominal amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale or purchase of the underlying physical commodity, resulting in a substantial diminution in our profitability and liquidity. As a result of these factors, our derivative activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows.

In addition, our hedging transactions are subject to the following risks:

- we may be limited in receiving the full benefit of increases in oil and gas prices as a result of these transactions;
- a counterparty may not perform its obligation under the applicable derivative financial instrument or may seek bankruptcy protection;
- there may be a change in the expected differential between the underlying commodity price in the derivative instrument and the actual price received; and
- the steps we take to monitor our derivative financial instruments may not detect and prevent violations of our risk management policies and procedures, particularly if deception or other intentional misconduct is involved.

The enactment of derivatives legislation and regulation could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price risks, interest rate risks and other risks associated with our business.

In 2010, new comprehensive financial reform legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank"), was enacted that established federal oversight regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. Dodd-Frank requires the Commodities Futures Trading Commission, or CFTC, the SEC and other regulators to promulgate rules and regulations implementing the new legislation. The final rules adopted under Dodd-Frank identify the types of products and the classes of market participants subject to regulation and will require us in connection with certain derivatives activities to comply with clearing and trade-execution requirements (or take steps to qualify for an exemption from such requirements). While most of the regulations have been finalized, it is not possible at this time to predict with certainty the full effects of Dodd-Frank and CFTC rules on us or the timing of such effects. We believe that Dodd-Frank and associated regulations could significantly increase the cost of derivative contracts from additional recordkeeping and reporting requirements and through requirements to post collateral which could adversely affect our available liquidity. If we reduce our use of derivatives as a result of Dodd-Frank and associated regulations, 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. These consequences could have a material adverse effect on our consolidated financial position, results of operations and cash flows.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays as well as restrict our access to our oil and gas reserves.

Hydraulic fracturing is an essential and common practice that is used to stimulate production of oil and natural gas from dense subsurface rock formations such as shale and tight sands. We routinely apply hydraulic fracturing techniques in completing our wells. The process involves the injection of water, sand and additives under pressure into a targeted subsurface formation. The water and pressure create fractures in the rock formations, which are held open by the grains of sand, enabling the oil or natural gas to flow to the wellbore. The use of hydraulic fracturing is necessary to produce commercial quantities of oil and natural gas from many reservoirs including the Haynesville shale, Bossier shale, Eagle Ford shale, Tuscaloosa Marine shale, Cotton Valley and other tight natural gas and oil reservoirs. Substantially all of our proved oil and gas reserves that are currently not producing and our undeveloped acreage require hydraulic fracturing to be productive. All of the wells currently being drilled by us utilize hydraulic fracturing in their completion and hydraulic fracturing services comprise approximately 45% of our capital budget in 2019.

The use of hydraulic fracturing in our well completion activities could expose us to liability for negative environmental effects that might occur. Although we have not had any incidents related to hydraulic fracturing operations that we believe have caused any negative environmental effects, we have established operating procedures to respond and report any unexpected fluid discharge which might occur during our operations, including plans to remediate any spills that might occur. In the event that we were to suffer a loss related to hydraulic fracturing operations, our insurance coverage will be net of a deductible per occurrence and our ability to recover costs will be limited to a total aggregate policy limit of $26.0 million, which may or may not be sufficient to pay the full amount of our losses incurred.

Drilling and completion activities are typically regulated by state oil and natural gas commissions. Our drilling and completion activities are conducted primarily in Louisiana and Texas. Texas adopted a law in June 2012 requiring disclosure to the Railroad Commission of Texas and the public of certain information regarding the components used in the hydraulic-fracturing process. In addition, Congress has considered legislation that, if implemented, would subject the process of hydraulic fracturing to regulation under the Safe Drinking Water Act. In June 2015, the EPA released a draft report on the potential impacts of hydraulic fracturing on drinking water resources, which concluded that hydraulic fracturing activities have not led to widespread, systemic impacts on drinking water resources in the United States, although there may be above and below ground mechanisms by which hydraulic fracturing activities have the potential to impact drinking water resources. The draft report was finalized in December 2016. Other governmental agencies, including the U.S. Department of Energy, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies have the potential to impact the likelihood or scope of future legislation or regulation.

State and federal regulatory agencies have recently focused on a possible connection between the hydraulic fracturing related activities and the increased occurrence of seismic activity. When caused by human activity, such events are called induced seismicity. In a few instances, operators of injection wells in the vicinity of seismic events have been ordered to reduce injection volumes or suspend operations. Some state regulatory agencies, including those in Colorado, Ohio, Oklahoma, and Texas, have modified their regulations to account for induced seismicity. Regulatory agencies at all levels are continuing to study the possible linkage between oil and gas activity and induced seismicity. A 2012 report published by the National Academy of Sciences concluded that only a very small fraction of the tens of thousands of injection wells have been suspected to be, or have been, the likely cause of induced seismicity; and a 2015 report by researchers at the University of Texas has suggested that the link between seismic activity and wastewater disposal may vary by region. In 2015, the United States Geological Survey identified eight states, including Texas, with areas of increased rates of induced seismicity that could be attributed to fluid injection or oil and gas extraction. More recently, in March 2016, the United States Geological Survey identified six states with the most significant hazards from induced seismicity, including Texas, Colorado, Oklahoma, Kansas, New Mexico, and Arkansas. In addition, a number of lawsuits have been filed, most recently in Oklahoma, alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. These developments could result in additional regulation and restrictions on the use of injection wells and hydraulic fracturing.

Changes in taxation as well as the inherent difficulty in quantifying potential tax effects of business decisions could have a material adverse effect on our results of operations, financial condition, or cash flows.

We make judgments regarding the utilization of existing income tax credits and the potential tax effects of various financial transactions and results of operations to estimate our obligations to taxing authorities. Tax obligations include income, franchise, real estate, sales and use, and employment-related taxes. These judgments include reserves for potential adverse outcomes regarding tax positions that have been taken. Changes in federal, state, or local tax laws, adverse tax audit results, or adverse tax rulings on positions taken by us could have a material adverse effect on our results of operations, financial condition, or cash flows.

The Budget Reconciliation Act, commonly referred to as the Tax Cuts and Jobs Act (hereinafter "Tax Cuts and Jobs Act"), was signed into law on December 22, 2017. The Tax Cuts and Jobs Act resulted in a net tax benefit to us of approximately $20.4 million, which is attributable primarily to the termination of the corporate alternative minimum tax. The Tax Cuts and Jobs Act is expected to have a favorable impact on our effective tax rate and net income as reported under generally accepted accounting principles in future reporting periods to which the Tax Cuts and Jobs Act is effective. However, we are still assessing the full impact of the Tax Cuts and Jobs Act, including the impact on state taxes, and there can be no assurances that it will have a favorable impact on us or our future financial results.

Loss of our information and computer systems could adversely affect our business.

We are heavily dependent on our information systems and computer-based programs, including our well operations information, seismic data, electronic data processing and accounting data. If any of these programs or systems were to fail or create erroneous information in our hardware or software network infrastructure, possible consequences include loss of our communication links, our inability to find, produce, process and sell oil and natural gas and the inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any of these consequences could have a material effect on our business.

Our business could be negatively impacted by security threats, including cyber-security threats and other disruptions.

As an oil and natural gas producer, we face various security threats, including cyber-security threats to gain unauthorized access to sensitive information or to render data or systems unusable, threats to the safety of our employees, threats to the security or operation of our facilities and infrastructure or third party facilities and infrastructure, such as processing plants and pipelines, and threats from terrorist acts. Cyber-security attacks in particular are evolving and include, but are not limited to, malicious software, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. Although we utilize various procedures and controls to monitor and protect against these threats and to mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing. If any of these events were to materialize, either to the Company or a third party upon which we rely, they could lead to losses of sensitive information, critical infrastructure, personnel or capabilities, essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations, or cash flows.

We are exposed to the credit risk of our customers and counterparties, and our credit risk management may not be adequate to protect against such risk.

We are subject to the risk of loss resulting from nonpayment and/or nonperformance by our customers and counterparties in the ordinary course of our business. Our credit procedures and policies may not be adequate to fully eliminate customer and counterparty credit risk particularly in light of the sustained declines in oil and natural gas prices since mid-2014. We cannot predict to what extent our business would be impacted by deteriorating conditions in the economy, including declines in our customers' and counterparties' creditworthiness. If we fail to adequately assess the creditworthiness of existing or future customers and counterparties, unanticipated deterioration in their creditworthiness and any resulting increase in nonpayment and/or nonperformance by them could cause us to write-down or write-off doubtful accounts. Such write-downs or write-offs could negatively affect our operating results in the periods in which they occur and, if significant, could have a material adverse effect on our business, results of operations, cash flows and financial condition.

Substantial exploration and development activities could require significant outside capital, which could dilute the value of our common shares and restrict our activities. Also, we may not be able to obtain needed capital or financing on satisfactory terms, which could lead to a limitation of our future business opportunities and a decline in our oil and natural gas reserves.

We expect to expend substantial capital in the acquisition of, exploration for and development of oil and natural gas reserves. In order to finance these activities, we may need to alter or increase our capitalization substantially through the issuance of debt or equity securities, the sale of non-strategic assets or other means. The issuance of additional equity securities could have a dilutive effect on the value of our common shares, and may not be possible on terms acceptable to us given the current volatility in the financial markets. The issuance of additional debt would likely require that a portion of our cash flow from operations be used for the payment of interest on our debt, thereby reducing our ability to use our cash flow to fund working capital, capital expenditures, acquisitions, dividends and general corporate requirements, which could place us at a competitive disadvantage relative to other competitors. Our cash flow from operations and access to capital is subject to a number of variables, including:

- our estimated proved reserves;
- the level of oil and natural gas we are able to produce from existing wells;
- our ability to extract natural gas liquids from the natural gas we produce;
- the prices at which oil, natural gas liquids and natural gas are sold; and
- our ability to acquire, locate and produce new reserves.

If our revenues decrease as a result of lower oil or natural gas prices, operating difficulties or declines in reserves, our ability to obtain the capital necessary to undertake or complete future exploration and development programs and to pursue other opportunities may be limited, which could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could result in a decline in our oil and natural gas reserves.

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

Our industry has experienced a shortage of drilling rigs, equipment, supplies and qualified personnel in prior years as the result of higher demand for these services. Shortages of drilling rigs, equipment, supplies or qualified personnel in the areas in which we operate could delay or restrict our exploration and development operations, which in turn could adversely affect our financial condition and results of operations because of our concentration in those areas.

We depend on our key personnel and the loss of any of these individuals could have a material adverse effect on our operations.

We believe that the success of our business strategy and our ability to operate profitably depend on the continued employment of M. Jay Allison, our Chief Executive Officer, and Roland O. Burns, our President and Chief Financial Officer, and a limited number of other senior management personnel. Loss of the services of Mr. Allison, Mr. Burns or any of those other individuals could have a material adverse effect on our operations.

Our insurance coverage may not be sufficient or may not be available to cover some liabilities or losses that we may incur.

If we suffer a significant accident or other loss, our insurance coverage will be net of our deductibles and may not be sufficient to pay the full current market value or current replacement value of our lost investment, which could result in a material adverse impact on our operations and financial condition. Our insurance does not protect us against all operational risks. We do not carry business interruption insurance. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. Because third party drilling contractors are used to drill our wells, we may not realize the full benefit of workers' compensation laws in dealing with their employees. In addition, some risks, including pollution and environmental risks, generally are not fully insurable.

Provisions of our restated articles of incorporation, bylaws and Nevada law will make it more difficult to effect a change in control of us, which could adversely affect the price of our common stock.

Nevada corporate law and our restated articles of incorporation and bylaws contain provisions that could delay, defer or prevent a change in control of us. These provisions include:

- allowing for authorized but unissued shares of common and preferred stock;
- requiring special stockholder meetings to be called only by our chairman of the board, our chief executive officer, a majority of the board, a majority of our executive committee or the holders of a majority of our outstanding stock;
- requiring removal of directors by a supermajority stockholder vote;
- prohibiting cumulative voting in the election of directors; and
- Nevada control share laws that may limit voting rights in shares representing a controlling interest in us.

These provisions could make an acquisition of us by means of a tender offer or proxy contest or removal of our incumbent directors more difficult. As a result, these provisions could make it more difficult for a third party to acquire us, even if doing so would benefit our stockholders, which may limit the price that investors are willing to pay in the future for shares of our common stock.

The Company is controlled by significant stockholders who have the power to determine the outcome of all matters submitted to the stockholders for approval and whose interest in the Company may be different than yours.

As of December 31, 2018, the Jones Partnerships, owned in the aggregate approximately 84% of our outstanding common stock. This would give the Jones Partnerships the power to:

- control the Company's management and policies; and
- determine the outcome of any corporate transaction or other matter requiring stockholder approval, including charter amendments, mergers, consolidations, financings and asset sales.

The Jones Partnerships may have interests that are different than yours in making these decisions.

ITEM 1B. *UNRESOLVED STAFF COMMENTS*

None.

ITEM 3. *LEGAL PROCEEDINGS*

We are not a party to any legal proceedings which management believes will have a material adverse effect on our consolidated results of operations or financial condition.

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 common stock is listed for trading on the New York Stock Exchange under the symbol "CRK". As of March 1, 2019, we had 105,871,064 shares of common stock outstanding, which were held by 74 holders of record and approximately 9,700 beneficial owners who maintain their shares in "street name" accounts.

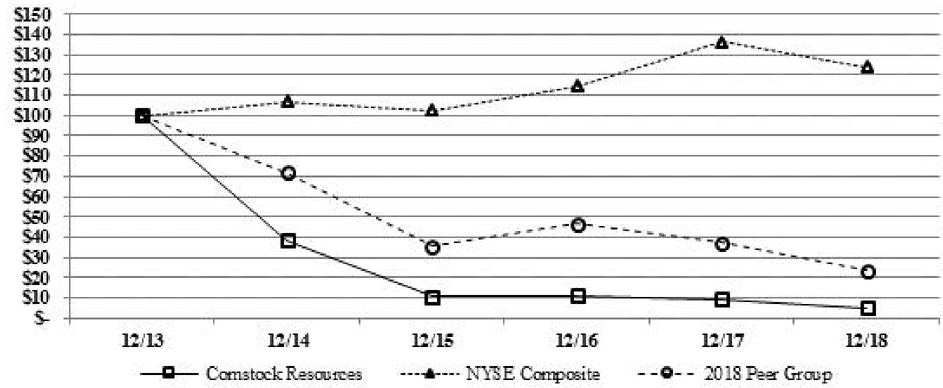
We have not paid dividend on our common stock since 2014. Any future determination as to the payment of dividends will depend upon the results of our operations, capital requirements, our financial condition and such other factors as our board of directors may deem relevant.

Stockholder Return Performance

A peer group of companies is used by our compensation committee to benchmark our executives' compensation and to determine total stockholder return performance for purposes of vesting of performance share units granted to executives under our 2009 Long-term Incentive Plan. For 2018, the compensation committee utilized a peer group, which consisted of Antero Resources Corporation, Approach Resources, Inc., Cabot Oil & Gas Corporation, Contango Oil & Gas Company, CNX Resources Corporation, Eclipse Resources Corporation, EQT Corporation, Goodrich Petroleum Corporation, Gulfport Energy Corporation, QEP Resources, Inc., Range Resources Corporation, SilverBow Resources, Inc., Southwestern Energy Company and Ultra Petroleum Corporation.

The following graph compares the yearly percentage change in the cumulative total stockholder return on our common stock during the five years ended December 31, 2018 with the cumulative return on the New York Stock Exchange Index and the cumulative return for our peer group. The graph assumes that $100.00 was invested on the last trading day of 2013, and that dividends, if any, were reinvested.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN(1)(2)
Among Comstock, the NYSE Composite Index, and Our Peer Group



(1) $100 invested on December 31, 2013 in stock or index, including reinvestment of dividends, fiscal year ending December 31.
(2) The data contained in the above graph is deemed to be furnished and not filed pursuant to Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liabilities of that section.

Total Return Analysis	As of December 31, 2013	2014	2015	2016	2017	2018
Comstock	$ 100.00	$ 38.47	$ 10.56	$ 11.13	$ 9.56	$ 5.12
NYSE Composite	$ 100.00	$ 106.75	$ 102.38	$ 114.61	$ 136.07	$ 123.89
Peer Group	$ 100.00	$ 71.78	$ 35.32	$ 46.46	$ 37.43	$ 23.41

ITEM 6. ***SELECTED FINANCIAL DATA***

The historical financial data presented in the table below as of and for each of the four years ended December 31, 2017, for the Predecessor Period from January 1, 2018 through August 13, 2018 and for the Successor Period from August 14, 2018 through December 31, 2018 are derived from our consolidated financial statements. The financial results are not necessarily indicative of our future operations or future financial results. The data presented below should be read in conjunction with our consolidated financial statements and the notes thereto and "Management's Discussion and Analysis of Financial Condition and Results of Operations".

Statement of Operations Data:

	Predecessor					Successor
	Year Ended December 31,					
	2014	2015	2016	2017	For the Period from January 1, 2018 through August 13, 2018	For the Period from August 14, 2018 through December 31, 2018
	(In thousands, except per share data)					
Revenues:						
Natural gas sales	$ 165,461	$ 109,753	$ 122,623	$ 208,741	$ 147,897	$ 144,236
Oil sales	389,770	142,669	53,083	46,590	18,733	79,385
Total oil and gas sales	555,231	252,422	175,706	255,331	166,630	223,621
Operating expenses:						
Production taxes	23,797	10,286	4,933	5,373	3,659	11,155
Gathering and transportation	12,897	14,298	15,824	17,538	11,841	10,511
Lease operating(1)	60,283	64,502	47,696	37,859	21,139	20,736
Exploration	19,403	70,694	84,144	—	—	—
Depreciation, depletion and amortization	378,275	321,323	141,487	123,557	68,032	53,944
General and administrative	32,379	23,541	23,963	26,137	15,699	11,399
Impairment of oil and gas properties	60,268	801,347	27,134	43,990	—	—
Loss (gain) on sale of oil and gas properties	—	112,085	14,315	1,060	35,438	(155)
Total operating expenses	587,302	1,418,076	359,496	255,514	155,808	107,590
Operating income (loss)	(32,071)	(1,165,654)	(183,790)	(183)	10,822	116,031
Other income (expenses):						
Gain (loss) from derivative financial instruments	8,175	2,676	(5,356)	16,753	881	10,465
Gain on extinguishment of debt	—	78,741	189,052	—	—	—
Transaction costs	—	—	—	—	(2,866)	—
Interest expense	(58,631)	(118,592)	(128,743)	(146,449)	(101,203)	(43,603)
Other income	727	1,275	872	530	677	173
Total other income (expenses)	(49,729)	(35,900)	55,825	(129,166)	(102,511)	(32,965)
Income (loss) before income taxes	(81,800)	(1,201,554)	(127,965)	(129,349)	(91,689)	83,066
Benefit from (provision for) income taxes	24,689	154,445	(7,169)	17,944	(1,065)	(18,944)
Net income (loss)	$ (57,111)	$ (1,047,109)	$ (135,134)	$ (111,405)	$ (92,754)	$ 64,122
Basic and diluted net income (loss) per share	$ (6.20)	$ (113.53)	$ (11.52)	$ (7.61)	$ (6.08)	$ 0.61
Dividends per common share	$ 2.50	$ —	$ —	$ —	$ —	$ —
Weighted average shares outstanding						
Basic	9,309	9,223	11,729	14,644	15,262	105,453
Diluted	9,309	9,223	11,729	14,644	15,262	105,459

(1) Includes ad valorem taxes.

Balance Sheet Data:

	As of December 31,				
	Predecessor				Successor
	2014	2015	2016	2017	2018
	(In thousands)				
Cash and cash equivalents	$ 2,071	$ 134,006	$ 65,904	$ 61,255	$ 23,193
Property and equipment, net	2,198,169	1,038,420	798,662	607,929	1,667,979
Total assets	2,264,546	1,195,850	889,874	930,419	2,187,840
Total debt	1,060,654	1,249,330	1,044,506	1,110,529	1,244,363
Stockholders' equity (deficit)	870,272	(171,258)	(271,269)	(369,272)	569,571

Cash Flow Data:

	Predecessor					Successor
	2014	2015	2016	2017	For the Period from January 1, 2018 through August 13, 2018	For the Period from August 14, 2018 through December 31, 2018
	(In thousands)					
Cash flows provided by (used for) operating activities	$ 400,984	$ 30,086	$ (23,728)	$ 174,614	$ 85,735	$ 102,302
Cash flows used for investing activities	(634,787)	(161,725)	(29,569)	(178,953)	(50,205)	(161,634)
Cash flows provided by (used for) financing activities	232,907	263,574	(14,805)	(310)	797,402	(811,662)

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

The following discussion and analysis should be read in conjunction with our selected historical consolidated financial data and our accompanying consolidated financial statements and the notes to those financial statements included elsewhere in this report. The following discussion includes forward-looking statements that reflect our plans, estimates and beliefs. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, those discussed below and elsewhere in this report, particularly in "Risk Factors" and "Cautionary Note Regarding Forward-Looking Statements." All share and per share data presented herein has been restated to give effect to our one-for-five (1:5) reverse stock split that became effective on July 29, 2016.

Jones Contribution

On August 14, 2018, the Jones Partnerships contributed certain oil and gas properties in North Dakota and Montana in exchange for 88,571,429 newly issued shares of common stock representing 84% of our outstanding common stock (the "Jones Contribution"). The Jones Partnerships are wholly owned and controlled by Dallas businessman Jerry Jones and his children (collectively, the "Jones Group"). References to "Successor" or "Successor Company" relate to the operations of the Company subsequent to August 13, 2018. References to "Predecessor" or "Predecessor Company" relate to the operations of the Company on or prior to August 13, 2018.

Overview

We are an independent energy company engaged in the acquisition, exploration, development and production of oil and natural gas in the United States. We own interests in 1,626 producing oil and natural gas wells (635.8 net to us) and we operate 608 of these wells. In managing our business, we are concerned primarily with maximizing return on our stockholders' equity. To accomplish this goal, we focus on profitably increasing our oil and natural gas reserves and production.

Our growth is driven primarily by our acquisition, development and exploration activities. In 2018 our growth in natural gas production and proved reserves was primarily driven by our successful acquisition and drilling activities. Our growth in oil production in 2018 was primarily due to the Bakken Shale properties contributed with the Jones Contribution. Under our current drilling budget, we plan to spend up to $364.0 million in 2019 for our development and exploration activities, which will be focused primarily on natural gas projects. We are currently planning to drill 58 horizontal natural gas wells (36.4 net to us) in 2019, targeting the Haynesville and Bossier shale and to complete 16 (5.7 net to us) wells drilled in 2018. The actual number of wells that we drill in 2019 will depend on natural gas prices as we intend to fund our drilling activities with the operating cash flow we generate.

We use the successful efforts method of accounting, which allows only for the capitalization of costs associated with developing proven oil and natural gas properties as well as exploration costs associated with successful exploration activities. Accordingly, our exploration costs consist of costs we incur to acquire and reprocess 3-D seismic data, impairments of our unevaluated leasehold where we were not successful in discovering reserves and the costs of unsuccessful exploratory wells that we drill.

We generally sell our oil and natural gas at current market prices at the point our wells connect to third party purchaser pipelines or terminals. We have entered into certain transportation and treating agreements with midstream and pipeline companies to transport a substantial portion of our natural gas production to long-haul gas pipelines. We market our products several different ways depending upon a number of factors, including the availability of purchasers for the product, the availability and cost of pipelines near our wells, market prices, pipeline constraints and operational flexibility. Accordingly, our revenues are heavily dependent upon the prices of, and demand for, oil and natural gas. Oil and natural gas prices have historically been volatile and are likely to remain volatile in the future.

Our operating costs are generally comprised of several components, including costs of field personnel, insurance, repair and maintenance costs, production supplies, fuel used in operations, transportation costs, workover expenses and state production and ad valorem taxes.

Like all oil and natural gas exploration and production companies, we face the constant challenge of replacing our reserves. Although in the past we have offset the effect of declining production rates from existing properties through successful acquisition and drilling efforts, there can be no assurance that we will be able to continue to offset production declines or maintain production at current rates through future acquisitions or drilling activity. Our future growth will depend on our ability to continue to add new reserves in excess of production.

Our operations and facilities are subject to extensive federal, state and local laws and regulations relating to the exploration for, and the development, production and transportation of, oil and natural gas, and operating safety. Future laws or regulations, any adverse changes in the interpretation of existing laws and regulations or our failure to comply with existing legal requirements may have an adverse effect on our business, results of operations and financial condition. Applicable environmental regulations require us to remove our equipment after production has ceased, to plug and abandon our wells and to remediate any environmental damage our operations may have caused. The present value of the estimated future costs to plug and abandon our oil and gas wells and to dismantle and remove our production facilities is included in our reserve for future abandonment costs, which was $5.1 million as of December 31, 2018.

Prices for crude oil and natural gas have been highly volatile, and we are currently experiencing a period of low prices primarily due to an oversupply of crude oil and natural gas. As prices remain low, we will continue to experience low revenues and cash flows. We expect our oil production to continue to decline as we have limited future plans to participate in the drilling of new oil wells. We expect our natural gas production to decline in the future to the extent that we do not offset this decline from production from the new wells we plan to drill in 2018 and future periods. Depending upon future prices and our production volumes, our cash flows from our operating activities may not be sufficient to fund our capital expenditures, and we may need to either curtail drilling activity or we may seek additional borrowings which would increase our interest expense in 2019 and in future periods.

We recognized $44.0 million of impairments of our proved oil and gas properties in 2017, primarily to adjust the carrying value of our assets held for sale to the estimated fair value less costs to sell at the end of the year. We may need to recognize further impairments if oil and natural gas prices remain low, and as a result, the expected future cash flows from these properties becomes insufficient to recover their carrying value.

To enhance the analysis of our operating results for the periods presented, we have included a discussion of selected financial and operating data of the Predecessor and Successor on a combined basis for the year ended December 31, 2018. This presentation consists of the mathematical addition of selected financial and operating data of the Predecessor for the period from January 1, 2018 to August 13, 2018 plus the comparable financial and operating data of the Successor for the period from August 14, 2018 to December 31, 2018. There are no other adjustments made in the combined presentation. The mathematical combination of selected financial and operating data is included below under the heading "Combined Year Ended December 31, 2018" and this data is a non-GAAP presentation. Management believes that this selected financial and operating data provides investors with useful information upon which to assess our operating performance because the results of operations for a twelve-month period correspond to how we have reported our results in the past and how we will report our results in the future.

Results of Operations

2018 Periods Compared to Year Ended December 31, 2017

Our operating data for the year ended December 31, 2017 ("Predecessor 2017"), the period January 1, 2018 through August 13, 2018 (the "2018 Predecessor Period") and the period August 14, 2018 through December 31, 2018 (the "2018 Successor Period") are summarized below:

	Predecessor		Successor	
	Year Ended December 31, 2017	For the Period from January 1, 2018 through August 13, 2018	For the Period from August 14, 2018 through December 31, 2018	Combined Year Ended December 31, 2018(3)
Oil and Gas Sales (in thousands):				
Natural gas sales	$ 208,741	$ 147,897	$ 144,236	$ 292,133
Oil sales	46,590	18,733	79,385	98,118
Total oil and gas sales	$ 255,331	$ 166,630	$ 223,621	$ 390,251
Net Production Data:				
Natural gas (MMcf)	73,521	55,240	45,031	100,271
Oil (MBbls)	951	287	1,385	1,672
Natural gas equivalent (MMcfe)	79,224	56,963	53,338	110,301
Average Sales Price:				
Natural gas ($/Mcf)	$ 2.84	$ 2.68	$ 3.20	$ 2.91
Oil ($/Bbl)	$ 49.02	$ 65.23	$ 57.34	$ 58.70
Average equivalent price ($/Mcfe)	$ 3.22	$ 2.93	$ 4.19	$ 3.54
Expenses ($ per Mcfe):				
Production taxes	$ 0.07	$ 0.06	$ 0.21	$ 0.13
Gathering and transportation	$ 0.22	$ 0.21	$ 0.20	$ 0.20
Lease operating(1)	$ 0.48	$ 0.37	$ 0.38	$ 0.39
Depreciation, depletion and amortization(2)	$ 1.55	$ 1.18	$ 1.01	

(1) Includes ad valorem taxes.
(2) Represents depreciation, depletion and amortization of oil and gas properties only.
(3) The combined year ended December 31, 2018 information is a provided for comparative purposes only and is a non-GAAP presentation.

Oil and gas sales. Oil and gas sales of $390.3 million in 2018 for the combined Predecessor and Successor Periods increased $134.9 million or 111% over Predecessor 2017 oil and gas sales of $255.3 million due to higher oil and natural gas production and higher natural gas prices. Natural gas sales increased by $83.4 million due to higher production related to our successful Haynesville shale drilling program, production from our Bakken shale properties that we added in mid-August 2018 and a 2% increase in our average realized natural gas price. The increase in oil sales of $51.5 million was attributable to the oil from the Bakken shale properties which more than offset the decrease resulting from our divesture of our Eagle Ford shale oil properties in April 2018.

Production taxes. Production taxes of $14.8 million for the 2018 combined Predecessor and Successor Periods increased $9.4 million or 176% from Predecessor 2017 production taxes of $5.4 million. This increase is primarily related to production taxes related to the Bakken shale properties.

Gathering and transportation. Gathering and transportation costs increased $4.8 million or 27% to $22.4 million in the 2018 combined Predecessor and Successor Periods as compared to $17.5 million in the Predecessor 2017. This increase primarily reflects the higher production from the Haynesville shale in 2018.

Lease operating expenses. Our lease operating expenses of $41.9 million in the 2018 combined Predecessor and Successor Periods were $4.0 million or 11% higher than our Predecessor 2017 lease operating expenses of $37.9 million. Operating expenses per Mcfe in the combined 2018 Predecessor and Successor Periods were $0.39 which was 19% less than the $0.48 per Mcfe for the Predecessor 2017. Much of our direct costs for our natural gas operations are fixed, and the higher natural gas production decreased our operating costs per Mcfe. This was partially offset by the additional lease operating expenses related to the Bakken shale properties.

Depreciation, depletion and amortization expense ("DD&A"). DD&A for the 2018 Successor Period was $53.9 million or $1.01 per Mcfe. DDA was $68.0 million or $1.18 per Mcfe for the 2018 Predecessor Period and $123.6 million or $1.55 per Mcfe for the Predecessor 2017. The decrease in DD&A in the 2018 Successor Period primarily resulted from a new basis being assigned to our proved oil and gas properties resulting from the Jones Contribution and the addition of the Bakken shale properties.

General and administrative expenses. General and administrative expense in the 2018 Successor Period of $11.4 million included $1.0 million of stock-based compensation. General and administrative costs of $15.7 million and $26.1 million for the 2018 Predecessor Period and the Predecessor 2017, respectively, included $3.9 million and $5.9 million for stock based compensation, respectively.

Derivative financial instruments. We utilized oil and natural gas price swaps and collars to manage our exposure to commodity prices and protect returns on investment from our drilling activities. We had gains on derivative financial instruments of $10.5 million during the 2018 Successor Period, $0.9 million during the 2018 Predecessor Period, and $16.8 million during the Predecessor 2017. Cash activity from derivative financial instruments included payments of $5.6 million during the 2018 Successor Period and receipts of $2.8 million and $9.4 million during the 2018 Predecessor Period and the Predecessor 2017, respectively. The following table presents our natural gas and oil equivalent prices before and after the effect of cash settlements of our derivative financial instruments:

	Predecessor		Successor
	Year Ended December 31, 2017	For the Period January 1, 2018 through August 13, 2018	For the Period August 14, 2018 through December 31, 2018
Average Realized Natural Gas Price:			
Natural gas, per Mcf	$2.84	$2.68	$3.20
Cash settlements on derivative financial instruments, per Mcf	0.13	0.05	(0.13)
Price per Mcf, including cash settlements on derivative financial instruments	$2.97	$2.73	$3.07
Average Realized Oil Price:			
Crude oil per Barrel	$49.02	$65.23	$57.34
Cash settlements on derivative financial instruments, per Barrel	—	—	0.46
Price per Barrel, including cash settlements on derivative financial instruments	$49.02	$65.23	$57.80

Interest expense. Interest expense was $43.6 million for the 2018 Successor Period and $101.2 million for the 2018 Predecessor Period as compared to $146.4 million for the Predecessor 2017. Interest for the 2018 Successor Period reflects our debt refinancing transaction that closed concurrent with the Jones Contribution in which we refinanced all of our then existing debt with the issuance of $850.0 million of new 9¾% Senior Notes due 2026 and $450.0 million of borrowings under a new bank credit facility that has a borrowing base of $700.0 million. Included in interest expense in the both the 2018 Predecessor Period and the Predecessor 2017 was amortization of the debt discounts recognized as a result of the gain recognized on the debt exchange that we completed in 2016 and the amortization of costs incurred on the exchange.

Income taxes. Income taxes were a provision of $18.9 million in the 2018 Successor Period, a provision of $1.1 million in the 2018 Predecessor Period and a benefit of $17.9 million in the Predecessor 2017. The effective tax rate was 23% in the 2018 Successor Period, a benefit of 1% for the 2018 Predecessor Period and 14% for the Predecessor 2017. Income taxes for the 2018 Successor Period differed from the federal income tax rate of 21% primarily due to the effect of state taxes and a tax benefit for the reduction of our valuation allowance. The effective tax rate for the 2018 Predecessor Period differs from the federal tax rate of 21% primarily due to a valuation allowance recognized on deferred tax assets and state taxes. Our effective tax rate of 14% in the Predecessor 2017 differed from the federal income tax rate of 35% primarily is due to recognition of the effect of the Tax Cuts and Jobs Act.

Net loss. We reported net income of $64.1 million or $0.61 per diluted share in the 2018 Successor Period, a net loss of $92.8 million or $6.08 per share for the 2018 Predecessor Period and a net loss of $111.4 million or $7.61 per share for the Predecessor 2017. The net income in the 2018 Predecessor Period reflects higher operating profit from oil and gas operations due to the contribution of the Bakken shale properties and lower interest expense due to our debt refinancing. The loss in the 2018 Predecessor Period was mainly due to the high interest expense which offset improved operating results. The loss during the Predecessor 2017 was primarily due to the higher interest costs and the impairment of our assets held for sale.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

Our operating data for 2016 and 2017 is summarized below:

	Predecessor	
	Year Ended December 31,	
	2016	2017
Oil and Gas Sales (in thousands):		
Natural gas sales	$ 122,623	$ 208,741
Oil sales	53,083	46,590
Total oil and gas sales	$ 175,706	$ 255,331
Net Production Data:		
Natural gas (MMcf)	53,678	73,521
Oil (MBbls)	1,388	951
Natural gas equivalent (MMcfe)	62,006	79,224
Average Sales Price:		
Natural gas ($/Mcf)	$ 2.28	$ 2.84
Oil ($/Bbl)	$ 38.24	$ 49.02
Average equivalent price ($/Mcfe)	$ 2.83	$ 3.22
Expenses ($ per Mcfe):		
Production taxes	$ 0.08	$ 0.07
Gathering and transportation	$ 0.26	$ 0.22
Lease operating(1)	$ 0.76	$ 0.48
Depreciation, depletion and amortization(2)	$ 2.26	$ 1.55

(1) Includes ad valorem taxes.
(2) Represents depreciation, depletion and amortization of oil and gas properties only.

Oil and gas sales. Our oil and gas sales increased $79.6 million (45%) in 2017 to $255.3 million from $175.7 million in 2016 primarily due to the growth in our natural gas production driven by our Haynesville shale drilling program and higher oil and natural gas prices. Natural gas sales increased by $86.1 million (70%) from 2016 while oil sales decreased by $6.5 million from 2016. Our natural gas production increased by 37% from 2016 while our realized natural gas prices increased by 25%. The decrease in oil sales was attributable to the 31% decline in oil production which was partially offset by a 28% increase in our realized oil prices in 2017.

Production taxes. Production taxes increased $0.5 million or 9% to $5.4 million in 2017 from $4.9 million in 2016. The increase in 2017 was mainly due to the higher natural gas volumes and prices, which was partially offset by our lower oil revenues. Much of our natural gas sales in 2016 and 2017 qualified for a temporary exemption from state production taxes.

Gathering and transportation. Gathering and transportation costs in 2017 increased $1.7 million (11%) to $17.5 million as compared to $15.8 million in 2016 due to the 37% increase in natural gas we produced during 2017. Gathering and transportation per Mcf produced improved from 2016 as we were able to reduce the rates on certain of our transportation contracts in 2016 and 2017.

Lease operating expenses. Our lease operating expenses, including ad valorem taxes, of $37.9 million in 2017 were $9.8 million or 21% lower than our operating expenses of $47.7 million in 2016. Our lease operating expense per Mcfe produced decreased by 37% to $0.48 per Mcfe in 2017 as compared to $0.76 per Mcfe in 2016. The decrease in operating costs mainly reflects the higher volumes of natural gas produced, and lower costs associated with our declining oil production.

Exploration expense. We incurred exploration expense of $84.1 million in 2016 related to impairments of unevaluated leasehold costs. We did not incur any exploration expense in 2017.

Depreciation, depletion and amortization expense. DD&A of $123.6 million decreased by $17.9 million (13%) from DD&A of $141.5 million in 2016. Our DD&A rate per Mcfe produced averaged $1.55 in 2017 as compared to $2.26 for 2016. The decrease in DD&A primarily resulted from the increase in production from our lower cost Haynesville shale properties.

General and administrative expenses. General and administrative expense of $26.1 million for 2017 was 9% higher than general and administrative expense of $24.0 million for 2016. The increase is primarily related to higher compensation costs for our employees. Stock-based compensation increased by $1.2 million to $5.9 million in 2017 as compared to $4.7 million in 2016.

Impairment of oil and gas properties. We recorded impairments to our oil and gas properties of $44.0 million and $27.1 million in 2017 and 2016, respectively. These impairments primarily relate to our South Texas oil assets held for sale at December 31, 2017 and our natural gas properties in South Texas that we sold in 2016.

Derivative financial instruments. We utilized oil and natural gas price swaps to manage our exposure to commodity prices and protect returns on investment from our drilling activities. We had a gain of $16.8 million and loss of $5.4 million on derivative financial instruments in 2017 and 2016, respectively. Our total net cash received from derivative financial instruments was $9.4 million in 2017 and $2.1 million in 2016.

The following table presents our natural gas and oil equivalent prices before and after the effect of cash settlements of our derivative financial instruments:

	Predecessor	
	Year Ended December 31,	
Average Realized Natural Gas Price:	**2016**	**2017**
Natural gas, per Mcf	$2.28	$2.84
Cash settlements on derivative financial instruments, per Mcf	0.04	0.13
Price per Mcf, including cash settlements on derivative financial instruments	$2.32	$2.97

Interest expense. Interest expense increased $17.7 million (14%) to $146.4 million in 2017 from interest expense of $128.7 million in 2016. The increase was primarily related to the amortization of the debt discounts recognized as a result of the gain recognized on the debt exchange that we completed in 2016 and the amortization of costs incurred on the exchange.

Income taxes. Income taxes decreased in 2017 to a benefit of $17.9 million from a provision of $7.2 million in 2016 due to the effect of the tax law change in 2017. Our effective tax rate of 14% in 2017 differed from the federal income tax rate of 35% primarily due to recognition of the effect of the Tax Cuts and Jobs Act, which primarily reflects the favorable effect of eliminating the corporate alternative minimum tax.

Net loss. We reported a net loss of $111.4 million or $7.61 per share for 2017 as compared to a loss of $135.1 million or $11.52 per share for 2016. The net loss in 2017 was primarily due to the amortization of debt premium and deferred financing costs related to our 2016 debt refinancing and the impairment of our assets held for sale. The net loss in 2016 was primarily due to impairments of proved and unproved properties and other exploration costs.

Liquidity and Capital Resources

Funding for our activities has historically been provided by our operating cash flow, debt or equity financings and asset sales. For the 2018 Successor Period our primary source of funds was operating cash flows and debt financings. Cash provided by operating activities for the 2018 Successor Period was $102.3 million. For the 2018 Predecessor Period our primary sources of funds was operating cash flow, proceeds from asset sales and debt financings. Cash flow from operating activities for the 2018 Predecessor Period were $85.7 million. The increase in operating cash flow during the 2018 Successor Period primarily reflects higher oil and gas sales resulting from the contributed Bakken shale properties and the growth in our natural gas production resulting from our Haynesville shale drilling activities.

For the Predecessor 2017, our primary source of funds was operating cash flow. Cash provided by operating activities in 2017 was $174.6 million as compared to cash used for operating activities of $23.7 million in 2016. The increase in operating cash flow in 2017 is primarily due to the growth in our natural gas production resulting from our drilling activities and higher oil and natural gas prices. For 2016, our primary source of funds was cash on hand and proceeds from asset sales of $27.9 million. Cash used for operating activities in 2016 was $23.7 million as compared to cash provided by operating activities of $30.1 million in 2015. The decrease in operating cash flow is primarily due to lower oil and gas revenues.

Our capital expenditure activity is summarized in the following table:

	Predecessor			Successor
	Year Ended December 31,		Period from January 1, 2018 through August 13, 2018	Period from August 14, 2018 through December 31, 2018
	2016	2017		
	(In thousands)			
Exploration and development:				
Acquisitions of proved oil and gas properties	$ —	$ —	$ 39,323	$ 21,013
Developmental leasehold costs	3,267	4,698	2,848	1,715
Development drilling and completion	50,711	164,472	90,840	148,745
Other development costs	5,569	9,644	13,871	13,612
	59,547	178,814	146,882	185,085
Other	69	43	31	2
Total	$ 59,616	$ 178,857	$ 146,913	$ 185,087

The timing of most of our capital expenditures is discretionary because we have no material long-term capital expenditure commitments. Consequently, we have a significant degree of flexibility to adjust the level of our capital expenditures as circumstances warrant. We currently expect to spend approximately $364.0 million in 2019 for development and exploration projects including drilling 58 horizontal wells, completing 16 wells drilled in 2018, and for other development projects. Our operating cash flow and, therefore, our capital expenditures are highly dependent on oil and natural gas prices that we realize in 2019. We operate most of the properties where we expect ongoing development and as a result have significant discretion over the amount and timing of our future capital expenditures.

We do not have a specific acquisition budget for 2019 because the timing and size of acquisitions are unpredictable. We intend to use borrowings under our bank credit facility, or other debt or equity financings to the extent available, to finance such acquisitions. The availability and attractiveness of these sources of financing will depend upon a number of factors, some of which will relate to our financial condition and performance and some of which will be beyond our control, such as prevailing interest rates, oil and natural gas prices and other market conditions. Lack of access to the debt or equity markets due to general economic conditions could impede our ability to complete acquisitions.

In connection with the Jones Contribution, we completed a series of refinancing transactions, including a private placement of $850.0 million of new unsecured 9¾% Senior Notes due 2026 and a new bank credit facility with an initial borrowing base of $700.0 million. We utilized the net proceeds from the notes offering, $450.0 million of borrowings under the new bank credit agreement and cash on hand to retire all of our then-outstanding senior secured and unsecured notes.

The senior notes placement closed on August 3, 2018. Interest on the notes is payable at an annual rate of 9¾% on February 15 and August 15 and the notes mature on August 15, 2026.

On August 14, 2018, we entered into a new bank credit facility with Bank of Montreal, as administrative agent, and the participating banks which matures on August 14, 2023. The bank credit facility is subject to a borrowing base of $700.0 million which is re-determined on a semi-annual basis and upon the occurrence of certain other events. As of December 31, 2018 there were $450.0 million of borrowings outstanding under the bank credit facility. Borrowings under the bank credit facility are secured by substantially all of our assets and those of our subsidiaries, and bear interest at our option, at either LIBOR plus 2.0% to 3% or a base rate plus 1% to 2%, in each case depending on the utilization of the borrowing base. We also pay a commitment fee of 0.5% on the unused borrowing base. The bank credit facility places certain restrictions upon our, and our restricted subsidiaries' ability to, among other things, incur additional indebtedness, pay cash dividends, repurchase common stock, make certain loans, investments and divestitures and redeem the new senior notes. The only financial covenants are the maintenance of a leverage ratio of less than 4.0 to 1.0 and a current ratio of at least 1.0 to 1.0. We were in compliance with these covenants as of December 31, 2018.

The following table summarizes our aggregate liabilities and commitments by year of maturity:

	2019	2020	2021	2022	2023	Thereafter	Total
Bank credit facility	$ —	$ —	$ —	$ —	$ 450,000	$ —	$ 450,000
9¾% Senior Notes due 2026	—	—	—	—	—	850,000	850,000
Interest	103,845	103,845	103,845	103,845	95,981	224,453	735,814
Operating leases	1,560	1,560	1,560	—	—	—	4,680
Transportation	683	—	—	—	—	—	683
Drilling rigs	17,031	—	—	—	—	—	17,031
	$ 123,119	$ 105,405	$ 105,405	$ 103,845	$ 545,981	$ 1,074,453	$ 2,058,208

Future interest costs are based upon the effective interest rates of our outstanding senior notes and our borrowings under our bank credit facility.

We have obligations to incur future payments for dismantlement, abandonment and restoration costs of oil and gas properties. These payments are currently estimated to be incurred primarily after 2023. We record a separate liability for these asset retirement obligations, which totaled $5.1 million as of December 31, 2018.

We believe that our cash on hand and cash flow from operations and available borrowings under our bank credit facility is sufficient to fund our 2019 planned drilling activities. If our plans or assumptions change or our assumptions prove to be inaccurate, we may be required to seek additional capital, including additional equity or debt financings to replace any liquidity that may be lost from low oil and natural gas prices. We cannot provide any assurance that we will be able to obtain such capital, or if such capital is available, that we will be able to obtain it on acceptable terms.

Federal and State Taxation

The Tax Cuts and Jobs Act, which was enacted on December 22, 2017, reduced the corporate income tax rate effective January l, 2018 from 35% to 21%. Among the other significant tax law changes that potentially affect us are the elimination of the corporate alternative minimum tax ("AMT"), changes that require operating losses incurred in 2018 and beyond be carried forward indefinitely with no carryback up to 80% of taxable income in a given year, and limitations on the deduction for interest expense incurred in 2018 or later of up to 30% of its adjusted taxable income (defined as taxable income before interest and net operating losses) for the taxable year. For the tax years beginning before January 1, 2022, the adjusted taxable income for these purposes is also adjusted to exclude the impact of depreciation, depletion and amortization. The Tax Cuts and Jobs Act preserved deductibility of intangible drilling costs for federal income tax purposes, which allows us to deduct a portion of drilling costs in the year incurred and minimizes current taxes payable in periods of taxable income. At December 31, 2018, we have completed the accounting for the tax effects of enactment of the Tax Cuts and Jobs Act. We have remeasured certain deferred federal tax assets and liabilities based on the rates at which they are expected to reverse in the future, which is generally 21%. The amount recognized related to the remeasurement of our deferred federal tax balance was $140.4 million, which was subject to a valuation allowance. The Tax Cuts and Jobs Act repealed the AMT for tax years beginning on or after January 1, 2018 and provides that existing AMT credit carryforwards can be utilized to offset federal taxes for any taxable year. In addition, 50% of any unused AMT credit carryforwards can be refunded during tax years 2018 through 2020. We had $20.4 million of unused AMT credit carryforwards at December 31, 2018.

At December 31, 2018, we had $1.1 billion in U.S. federal net operating loss carryforwards and $1.5 billion in certain state net operating loss carryforwards. The shares of common stock issued as a result of the Jones Contribution triggered an ownership change under Section 382 of the Internal Revenue Code. As a result, our ability to use net operating losses ("NOLs") generated before the change in control to reduce taxable income is generally limited to an annual amount based on the fair market value of our stock immediately prior to the ownership change multiplied by the long-term tax-exempt interest rate. Our NOLs are estimated to be limited to $3.3 million a year as a result of this limitation. In addition to this limitation, IRC Section 382 provides that a corporation with a net unrealized built-in gain immediately before an ownership change may increase its limitation by the amount of built-in gain recognized during a recognition period, which is generally the five-year period immediately following an ownership change. Based on the fair market value of our common stock immediately prior to the ownership change, we believe that we have a net unrealized built-in gain which will increase the Section 382 limitation during the five-year recognition period.

NOLs that exceed the Section 382 limitation in any year continue to be allowed as carryforwards until they expire and can be used to offset taxable income for years within the carryover period subject to the limitation in each year. NOLs incurred prior to 2018 generally have a 20-year life until they expire. NOLs generated in 2018 and after would be carried forward indefinitely. Our use of new NOLs arising after the date of an ownership change would not be affected by the 382 limitation. If we do not generate a sufficient level of taxable income prior to the expiration of the pre-2018 NOL carry-forward periods, then we will lose the ability to apply those NOLs as offsets to future taxable income. We estimate that $843.0 million of the U.S. federal NOL carryforwards and $1.3 billion of the estimated state NOL carryforwards will expire unused.

Our federal income tax returns for the years subsequent to December 31, 2014 remain subject to examination. Our income tax returns in major state income tax jurisdictions remain subject to examination for various periods subsequent to December 31, 2012. We currently believe that our significant filing positions are highly certain and that all of our other significant income tax filing positions and deductions would be sustained upon audit or the final resolution would not have a material effect on our consolidated financial statements. Therefore, we have not established any significant reserves for uncertain tax positions.

Critical Accounting Policies

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires us to make estimates and use assumptions that can affect the reported amounts of assets, liabilities, revenues or expenses.

Successful efforts accounting. We are required to select among alternative acceptable accounting policies. There are two generally acceptable methods for accounting for oil and gas producing activities. The full cost method allows the capitalization of all costs associated with finding oil and natural gas reserves, including certain general and administrative expenses. The successful efforts method allows only for the capitalization of costs associated with developing proven oil and natural gas properties as well as exploration costs associated with successful exploration projects. Costs related to exploration that are not successful are expensed when it is determined that commercially productive oil and gas reserves were not found. We have elected to use the successful efforts method to account for our oil and gas activities and we do not capitalize any of our general and administrative expenses.

Oil and natural gas reserve quantities. The determination of depreciation, depletion and amortization expense is highly dependent on the estimates of the proved oil and natural gas reserves attributable to our properties. The determination of whether impairments should be recognized on our oil and gas properties is also dependent on these estimates, as well as estimates of probable reserves. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured. The accuracy of any reserve estimate depends on the quality of available data, production history and engineering and geological interpretation and judgment. Because all reserve estimates are to some degree imprecise, the quantities and timing of oil and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future oil and natural gas prices may all differ materially from those assumed in these estimates. The information regarding present value of the future net cash flows attributable to our proved oil and natural gas reserves are estimates only and should not be construed as the current market value of the estimated oil and natural gas reserves attributable to our properties. Thus, such information includes revisions of certain reserve estimates attributable to proved properties included in the preceding year's estimates. Such revisions reflect additional information from subsequent activities, production history of the properties involved and any adjustments in the projected economic life of such properties resulting from changes in product prices. Any future downward revisions could adversely affect our financial condition, our future prospects and the value of our common stock.

Impairment of oil and gas properties. We evaluate our proved properties for potential impairment when circumstances indicate that the carrying value of an asset may not be recoverable. If impairment is indicated based on a comparison of the asset's carrying value to its undiscounted expected future net cash flows, then it is recognized to the extent that the carrying value exceeds fair value. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Expected future cash flows are determined using estimated future prices based on market based forward prices applied to projected future production volumes. The projected production volumes are based on the property's proved and risk adjusted probable oil and natural gas reserves estimates at the end of the period. The estimated future cash flows that we use in our assessment of the need for an impairment are based on a corporate forecast which considers forecasts from multiple independent price forecasts. Prices are not escalated to levels that exceed observed historical market prices. Costs are also assumed to escalate at a rate that is based on our historical experience, currently estimated at 2% per annum. The oil and natural gas prices used for determining asset impairments will generally differ from those used in the standardized measure of discounted future net cash flows because the standardized measure requires the use of the average first day of the month historical price for the year. Unproved properties are evaluated for impairment based upon the results of drilling, planned future drilling and the terms of our oil and gas leases. During 2017, we recognized impairment charges of $44.0 million to reduce the capitalized costs of our proved oil and natural gas properties. It is reasonably possible that our estimates of undiscounted future net cash flows attributable to its oil and gas properties may change in the future. The primary factors that may affect estimates of future cash flows include future adjustments, both positive and negative, to proved and appropriate risk-adjusted probable oil and gas reserves, results of future drilling activities, future prices for oil and natural gas, and increases or decreases in production and capital costs. As a result of these changes, there may be further impairments in the carrying values of our proved and unproved oil and gas properties.

Goodwill. We have goodwill of $350.2 million as of December 31, 2018 that was recorded in connection with the Jones Contribution. Goodwill represents the excess of purchase price over fair value of net tangible and identifiable intangible assets. We are not required to amortize goodwill as a charge to earnings; however, the Company is required to conduct an annual review of goodwill for impairment.

We determine the potential for impairment of our goodwill by initially preparing a qualitative fair value assessment of our business value. In performing this qualitative assessment, we examine relevant events and circumstances that could have a negative effect on our business, including macroeconomic conditions, industry and market conditions (including current commodity price), earnings and cash flows, overall financial performance and other relevant entity specific events.

If the qualitative assessment indicates that it is more likely than not that our business is impaired, a quantitative analysis would be performed to assess our fair value and to determine the amount of impairment, if any, that requires recognition. When performing a quantitative impairment assessment of goodwill, fair value is determined based on a combination of (i) recent market transactions, where available; and (ii) projected discounted cash flows (an income approach). Under the market approach, fair value would be estimated by a comparison to similar businesses whose securities are actively traded in the public market. This requires our management to make certain judgments, including the selection of comparable companies, comparable recent company asset transactions, transaction premiums and selected financial metrics. Under the income approach, fair value is based on the present value of expected future cash flows. The income approach is dependent on a number of factors including estimates of forecasted revenues, estimates of future operating, administrative and capital costs adjusted for inflation, projected reserves quantities, the probability of success for future exploration for and development of proved and unproved reserves, discount rates and other variables. Future cash flows are discounted using discount factors applied by us when assessing oil and gas acquisition opportunities and we believe provide a fair market value of our business. Negative revisions of estimated reserves quantities, sustained decreases in crude oil or natural gas prices, increases in future cost estimates, or divestitures could lead to reductions in expected future cash flows that would indicate potential impairment of all or a portion of goodwill in future periods.

If the carrying value of goodwill exceeds the fair value calculated using the quantitative approach, an impairment charge would be recorded for the difference between fair value and carrying value. If oil or natural gas prices decrease, drilling efforts are unsuccessful or our market capitalization declines, it is reasonably possible that additional impairments would need to be recognized.

Income Taxes. We account for income taxes using the asset and liability method, whereby deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax basis, as well as the future tax consequences attributable to the future utilization of existing tax net operating loss and other types of carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that the change in rate is enacted.

In recording deferred income tax assets, we consider whether it is more likely than not that some portion or all of our deferred income tax assets will be realized in the future. The ultimate realization of deferred income tax assets is dependent upon the generation of future taxable income during the periods in which those deferred income tax assets would be deductible. We believe that after considering all the available objective evidence, historical and prospective, with greater weight given to historical evidence, we are not able to determine that it is more likely than not that all of our deferred tax assets will be realized. As a result, we established valuation allowances for our deferred tax assets and U.S. federal and state net operating loss carryforwards that are not expected to be utilized due to the uncertainty of generating taxable income prior to the expiration of the carryforward periods. We will continue to assess the valuation allowances against deferred tax assets considering all available information obtained in future reporting periods.

Stock-based compensation. We follow the fair value based method in accounting for equity-based compensation. Under the fair value based method, compensation cost is measured at the grant date based on the fair value of the award and is recognized on a straight-line basis over the award vesting period.

Recent accounting pronouncements. In January 2017, the FASB issued Accounting Standards Update No. 2017-04 (ASU 2017-04) "Intangibles-Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment." ASU 2017-04 eliminates step two of the goodwill impairment test and specifies that goodwill impairment should be measured by comparing the fair value of a reporting unit with its carrying amount. ASU 2017-04 is effective for annual or interim goodwill impairment tests performed in fiscal years beginning after December 15, 2019 and early adoption is permitted. We have initially recognized goodwill in our financial statements for the quarter ended September 30, 2018 and we will assess the impact of ASU 2017-04 on our financial statements when we perform annual impairment assessments following adoption of this standard in 2020.

In February 2016, the FASB issued ASU No. 2016-02, Leases ("ASU 2016-02"). ASU 2016-02 requires lessees to include most leases on their balance sheets, but recognize lease costs in their financial statements in a manner similar to accounting for leases prior to ASC 2016-02. ASU 2016-02 is effective for annual periods ending after December 15, 2018 and interim periods thereafter. We have analyzed our major contracts for indications that they contain a lease, and have identified some leases that will need to be reflected as an asset and a liability in our consolidated balance sheet. We are adopting ASC 2016-02 beginning January 1, 2018. We are using the modified retrospective method of adoption for this new standard and we are applying several of the available transition practical expedients as part of our adoption. The adoption of ASC 2016-02 is not expected to have a significant effect on our results of operations, liquidity or financial position.

ITEM 7A. *QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK*

Oil and Natural Gas Prices

Our financial condition, results of operations and capital resources are highly dependent upon the prevailing market prices of oil and natural gas. These commodity prices are subject to wide fluctuations and market uncertainties due to a variety of factors that are beyond our control. Factors influencing oil and natural gas prices include the level of global demand for oil, the foreign supply of oil and natural gas, the establishment of and compliance with production quotas by oil exporting countries, weather conditions which determine the demand for natural gas, the price and availability of alternative fuels and overall economic conditions. It is impossible to predict future oil and natural gas prices with any degree of certainty. Sustained weakness in oil and natural gas prices may adversely affect our financial condition and results of operations, and may also reduce the amount of oil and natural gas reserves that we can produce economically. Any reduction in our oil and natural gas reserves, including reductions due to price fluctuations, can have an adverse effect on our ability to obtain capital for our exploration and development activities. Similarly, any improvements in oil and natural gas prices can have a favorable impact on our financial condition, results of operations and capital resources. Based on our oil and natural gas production in the Successor Period of August 14 through December 31, 2018, and taking into account any oil or natural gas price swap agreements we had in place, a $1.00 change in the price per barrel of oil would have resulted in a change in our cash flow for such period by approximately $1.3 million and a $0.10 change in the price per Mcf of natural gas would have changed our cash flow by approximately $3.6 million.

As of December 31, 2018, we have entered into natural gas price swap agreements to hedge approximately 8.7 billion cubic feet of our 2019 production at an average price of $3.84 per Mcf. We have also entered into natural gas collars to hedge approximately 34.1 Bcf of natural gas with an average floor price of $2.44 per Mcf and an average ceiling price of $3.45 per Mcf. We also have oil collars to hedge 1,163,100 barrels with an average floor price of $52.35 per barrel and an average ceiling price of $74.56 per barrel. None of our derivative contracts have margin requirements or collateral provisions that could require funding prior to the scheduled cash settlement date. The change in the fair value of our natural gas swaps that would result from a 10% change in commodities prices at December 31, 2018 would be $9.2 million. Such a change in fair value could be a gain or a loss depending on whether prices increase or decrease. Since December 31, 2018, we have entered into additional natural gas collars which hedge an additional 18.2 Bcf of natural gas at an average floor price of $2.51 per Mcf and an average ceiling price of $3.70 per Mcf and additional crude oil price collar agreements which hedge an additional 426 thousand barrels of oil with an average floor price of $44.63 per barrel and an average ceiling price of $65.79 per barrel.

Interest Rates

At December 31, 2018, we had approximately $1.3 billion principal amount of long-term debt outstanding. $850.0 million of this amount bears interest at a fixed rate of 9¾%. The fair market value of our fixed rate debt as of December 31, 2018 was $720.0 million based on the market price of approximately 85% of the face amount of such debt. At December 31, 2018, we had $450.0 million outstanding under our bank credit facility, which is subject to variable rates of interest that are tied to LIBOR or the corporate base rate, at our option. Any increase in these interest rates would have an adverse impact on our results of operations and cash flow. Based on borrowings outstanding at December 31, 2018, a 100 basis point change in interest rates would change our Successor Period interest expense on our variable rate debt by approximately $4.5 million.

ITEM 8. *FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA*

Our consolidated financial statements are included on pages F-1 to F-34 of this report.

We have prepared these financial statements in conformity with generally accepted accounting principles. We are responsible for the fairness and reliability of the financial statements and other financial data included in this report. In the preparation of the financial statements, it is necessary for us to make informed estimates and judgments based on currently available information on the effects of certain events and transactions.

Our registered independent public accountants, Ernst & Young LLP, are engaged to audit our financial statements and to express an opinion thereon. Their audit is conducted in accordance with auditing standards generally accepted in the United States to enable them to report whether the financial statements present fairly, in all material respects, our financial position and results of operations in accordance with accounting principles generally accepted in the United States.

The audit committee of our board of directors is comprised of three directors who are not our employees. This committee meets periodically with our independent public accountants and management. Our independent public accountants have full and free access to the audit committee to meet, with and without management being present, to discuss the results of their audits and the quality of our financial reporting.

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

None.

ITEM 9A. *CONTROLS AND PROCEDURES*

Evaluation of Controls and Procedures. Disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended, or the Exchange Act) are designed to provide reasonable assurance that information required to be disclosed in reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures.

We performed an evaluation of the effectiveness of our disclosure controls and procedures as of December 31, 2018. The evaluation was performed with the participation of senior management of each business segment and key corporate functions, and under the supervision of the Chief Executive Officer and Chief Financial Officer.

Based on our evaluation of our disclosure controls and procedures, our chief executive officer and chief financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2018 to provide reasonable assurance that information required to be disclosed by us in the reports filed or submitted by us under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and to provide reasonable assurance that information required to be disclosed by us 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.

Changes in Internal Control over Financial Reporting. There were no changes in our internal control over financial reporting during the quarter ended December 31, 2018 that materially affected or are reasonably likely to materially affect our internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting. We are responsible for establishing and maintaining adequate internal control over financial reporting for the Company. In order to evaluate the effectiveness of internal control over financial reporting, as required by Section 404 of the Sarbanes-Oxley Act, we conducted an assessment, including testing, using the criteria in Internal Control — Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). Our system of internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. 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. As of December 31, 2018, we assessed the effectiveness of the Company's internal control over financial reporting based on the COSO criteria, and based on that assessment we determined that the Company maintained effective internal control over financial reporting as of December 31, 2018.

Ernst & Young LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of the Company's internal control over financial reporting as of December 31, 2018. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting as of December 31, 2018, follows below.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders
Comstock Resources, Inc.

Opinion on Internal Control over Financial Reporting

We have audited Comstock Resources, Inc. and subsidiaries' internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Comstock Resources, Inc. and subsidiaries (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2017 (Predecessor) and 2018 (Successor), the related consolidated statements of operations, stockholders' equity and cash flows for the years ended December 31, 2016 and 2017 (Predecessor), the period January 1, 2018 through August 13, 2018 (Predecessor), and the period August 14, 2018 through December 31, 2018 (Successor), and the related notes and our report dated March 1, 2019 expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the US federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

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

Definition and Limitations of Internal Control Over Financial Reporting

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ ERNST & YOUNG LLP

Dallas, Texas
March 1, 2019

ITEM 9B. *OTHER INFORMATION*

None.

PART III

ITEM 10. *DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE*

The information required by this item is incorporated herein by reference to "Business – Directors and Executive Officers" in this Form 10-K and to our definitive proxy statement which will be filed with the SEC within 120 days after December 31, 2018.

Section 16(a) Beneficial Ownership Reporting Compliance. Our directors, executive officers and stockholders with ownership of 10% or greater are required, under Section 16(a) of the Securities Exchange Act of 1934, to file reports of their ownership and changes to their ownership of our securities with the SEC. Based solely on our review of the reports and any written representations we received that no other reports were required, we believe that, during the year ended December 31, 2018, all of our officers, directors and stockholders with ownership of 10% or greater complied with all Section 16(a) filing requirements applicable to them.

Code of Ethics. We have adopted a Code of Business Conduct and Ethics that is applicable to all of our directors, officers and employees as required by New York Stock Exchange rules. We have also adopted a Code of Ethics for Senior Financial Officers that is applicable to our Chief Executive Officer and Senior Financial Officers. Both the Code of Business Conduct and Ethics and Code of Ethics for Senior Financial Officers may be found on our website at www.comstockresources.com. Both of these documents are also available, without charge, to any stockholder upon request to: Comstock Resources, Inc., Attn: Investor Relations, 5300 Town and Country Blvd., Suite 500, Frisco, Texas 75034, (972) 668-8800. We intend to disclose any amendments or waivers to these codes that apply to our Chief Executive Officer and senior financial officers on our website in accordance with applicable SEC rules. Please see the definitive proxy statement for our 2019 annual meeting, which will be filed with the SEC within 120 days of December 31, 2018, for additional information regarding our corporate governance policies.

ITEM 11. *EXECUTIVE COMPENSATION*

The information required by this item is incorporated herein by reference to our definitive proxy statement which will be filed with the SEC within 120 days after December 31, 2018.

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

The following table summarizes certain information regarding our equity compensation plans as of December 31, 2018:

	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Number of securities authorized for future issuance under equity compensation plans (excluding outstanding options, warrants and rights)
Equity compensation plans approved by stockholders	829,090[(1)]	152,908

(1) Represents performance share unit awards equivalent to 829,090 shares that would be issuable based upon achievement of the maximum awards under the terms of the performance share unit awards.

We do not have any equity compensation plans that were not approved by stockholders.

Further information required by this item is incorporated herein by reference to our definitive proxy statement which will be filed with the SEC within 120 days after December 31, 2018.

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

The information required by this item is incorporated herein by reference to our definitive proxy statement which will be filed with the SEC within 120 days after December 31, 2018.

ITEM 14. *PRINCIPAL ACCOUNTANT FEES AND SERVICES*

The information required by this item is incorporated herein by reference to our definitive proxy statement which will be filed with the SEC within 120 days after December 31, 2018.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Financial Statements:

1. The following consolidated financial statements and notes of Comstock Resources, Inc. are included on Pages F-2 to F-34 of this report:

2. All financial statement schedules are omitted because they are not applicable, or are immaterial or the required information is presented in the consolidated financial statements or the related notes.

(b) Exhibits:

The exhibits to this report required to be filed pursuant to Item 15(c) are listed below.

Exhibit No.	Description
2.1	Contribution Agreement dated May 9, 2018, by and among Arkoma Drilling, L.P., Williston Drilling, L.P. and the Company (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K dated May 9, 2018).
2.2	Amendment No. 1 to the Contribution Agreement, dated as of August 14, 2018, by and among Arkoma Drilling, L.P., Williston Drilling, L.P. and the Company (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K dated August 13, 2018).
3.1	Second Amended and Restated Articles of Incorporation of the Company (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated August 13, 2018).
3.2	Amended and Restated Bylaws (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated August 21, 2014).
4.1	Indenture, dated as of August 3, 2018, by and between Comstock Escrow Corporation, as issuer, and American Stock Transfer & Trust Company LLC, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated August 3, 2018).
4.2	First Supplemental Indenture dated August 14, 2018 among the Company, the Guarantors and American Stock Transfer & Trust Company, LLC, as Trustee (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K dated August 13, 2018).
10.1	Credit Agreement dated as of August 14, 2018, among the Company, Bank of Montreal as Administrative Agent, BMO Capital Markets Corp., Capital One, National Association and Fifth Third Bank as Joint Lead Arrangers, Capital One, National Association and Fifth Third Bank as Co-Syndication Agents, Bank of America, N.A., Natixis and Regions Bank as Co-Documentation Agents and BMO Capital Markets Corp. as sole Bookrunner (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated August 13, 2018).
10.2	Registration Rights Agreement, dated as of August 3, 2018, by and between Comstock Escrow Corporation and Merrill Lynch, Pierce, Fenner & Smith Incorporated (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated August 3, 2018).
10.3#	Comstock Resources, Inc. 2009 Long-term Incentive Plan Amended and Restated Effective as of November 8, 2016 (incorporated by reference to Exhibit 99 to our Registration Statement on Form S-8 dated December 7, 2016).
10.4#	Employment Agreement dated September 7, 2018 by and between the Company and M. Jay Allison (Incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated September 7, 2018).
10.5#	Employment Agreement dated September 7, 2018 by and between the Company and Roland O. Burns (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated September 7, 2018).
10.6	Lease between Stonebriar I Office Partners, Ltd., and Comstock Resources, Inc. dated May 6, 2004 (incorporated by reference to Exhibit 10.24 to our Annual Report on Form 10-K for the year ended December 31, 2004).
10.7	First Amendment to the Lease Agreement dated August 25, 2005, between Stonebriar I Office Partners, Ltd. and Comstock Resources, Inc. (incorporated by reference to Exhibit 10.19 to our Annual Report on Form 10-K for the year ended December 31, 2005).
10.8	Second Amendment to the Lease Agreement dated October 15, 2007 between Stonebriar I Office Partners, Ltd. and Comstock Resources, Inc. (incorporated by reference to Exhibit 10.10 to our Annual Report on Form 10-K for the year ended December 31, 2008).

Exhibit No.	Description
10.9	Third Amendment to the Lease Agreement dated September 30, 2008 between Stonebriar I Office Partners, Ltd. and Comstock Resources, Inc. (incorporated by reference to Exhibit 10.11 to our Annual Report on Form 10-K for the year ended December 31, 2008).
10.10	Fourth Amendment to the Lease Agreement dated May 8, 2009 between Stonebriar I Office Partners, Ltd. and Comstock Resources, Inc. (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2009).
10.11	Fifth Amendment to the Lease Agreement dated June 15, 2011 between Stonebriar I Office Partners, Ltd. and Comstock Resources, Inc. (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2011).
21*	Subsidiaries of the Company.
23.1*	Consent of Ernst & Young LLP.
23.2*	Consent of Independent Petroleum Engineers.
31.1*	Chief Executive Officer certification under Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Chief Financial Officer certification under Section 302 of the Sarbanes-Oxley Act of 2002.
32.1+	Chief Executive Officer certification under Section 906 of the Sarbanes-Oxley Act of 2002.
32.2+	Chief Financial Officer certification under Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Report of Independent Petroleum Engineers on Proved Reserves as of December 31, 2018.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.LAB*	XBRL Labels Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document

* Filed herewith.
\+ Furnished herewith.
\# Management contract or compensatory plan document.

SIGNATURES

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

COMSTOCK RESOURCES, INC.

By: /s/ M. JAY ALLISON
M. Jay Allison
Chief Executive Officer
(Principal Executive Officer)

Date: March 1, 2019

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.

/s/ M. JAY ALLISON M. Jay Allison	Chief Executive Officer and Chairman of the Board of Directors (Principal Executive Officer)	March 1, 2019
/s/ ROLAND O. BURNS Roland O. Burns	President, Chief Financial Officer, Secretary and Director (Principal Financial and Accounting Officer)	March 1, 2019
/s/ ELIZABETH B. DAVIS Elizabeth B. Davis	Director	March 1, 2019
/s/ MORRIS E. FOSTER Morris E. Foster	Director	March 1, 2019
/s/ JIM L. TURNER Jim L. Turner	Director	March 1, 2019

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
Comstock Resources, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Comstock Resources, Inc. and subsidiaries (the Company) as of December 31, 2017 (Predecessor) and 2018 (Successor), the related consolidated statements of operations, stockholders' equity, and cash flows for the years ended December 31, 2016 and 2017 (Predecessor), the period January 1, 2018 through August 13, 2018 (Predecessor), and the period August 14, 2018 through December 31, 2018 (Successor), and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2017 (Predecessor) and 2018 (Successor), and the results of its operations and its cash flows for the years ended December 31, 2016 and 2017 (Predecessor), the period January 1, 2018 through August 13, 2018 (Predecessor), and the period August 14, 2018 through December 31, 2018 (Successor), in conformity with US generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated March 1, 2019 expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the US federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ ERNST & YOUNG LLP

We have served as the Company's auditor since 2003.
Dallas, Texas
March 1, 2019

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
As of December 31, 2017 and 2018

	Predecessor December 31, 2017	Successor December 31, 2018
	(In thousands)	
ASSETS		
Cash and Cash Equivalents	$ 61,255	$ 23,193
Accounts Receivable:		
Oil and gas sales	26,700	87,611
Joint interest operations	11,872	9,175
Derivative Financial Instruments	1,318	15,401
Income Taxes Receivable	—	10,218
Assets Held for Sale	198,615	—
Other Current Assets	2,745	13,829
Total current assets	302,505	159,427
Property and Equipment:		
Oil and gas properties, successful efforts method:		
Proved properties	2,631,750	1,682,164
Unproved properties	—	191,929
Other	18,918	4,442
Accumulated depreciation, depletion and amortization	(2,042,739)	(210,556)
Net property and equipment	607,929	1,667,979
Goodwill	—	350,214
Income Taxes Receivable	19,086	10,218
Other Assets	899	2
	$ 930,419	$ 2,187,840
LIABILITIES AND STOCKHOLDERS' EQUITY		
Accounts Payable	$ 126,034	$ 138,767
Accrued Expenses	42,455	68,086
Total current liabilities	168,489	206,853
Long-term Debt	1,110,529	1,244,363
Deferred Income Taxes	10,266	161,917
Reserve for Future Abandonment Costs	10,407	5,136
Total liabilities	1,299,691	1,618,269
Commitments and Contingencies		
Stockholders' Equity:		
Common stock—$0.50 par, 75,000,000 shares authorized, 15,427,561 shares issued and outstanding at December 31, 2017, 155,000,000 shares authorized, 105,871,064 shares issued and outstanding at December 31, 2018, respectively	7,714	52,936
Common stock warrants	3,557	—
Additional paid-in capital	546,696	452,513
Accumulated earnings (deficit)	(927,239)	64,122
Total stockholders' equity (deficit)	(369,272)	569,571
	$ 930,419	$ 2,187,840

The accompanying notes are an integral part of these statements.

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Predecessor			Successor
	Years Ended December 31,		Period from January 1, 2018 through August 13, 2018	Period from August 14, 2018 through December 31, 2018
	2016	2017		
	(In thousands, except per share amounts)			
Natural gas sales	$ 122,623	$ 208,741	$ 147,897	$ 144,236
Oil sales	53,083	46,590	18,733	79,385
Total oil and gas sales	175,706	255,331	166,630	223,621
Operating expenses:				
Production taxes	4,933	5,373	3,659	11,155
Gathering and transportation	15,824	17,538	11,841	10,511
Lease operating	47,696	37,859	21,139	20,736
Exploration	84,144	—	—	—
Depreciation, depletion and amortization	141,487	123,557	68,032	53,944
General and administrative, net	23,963	26,137	15,699	11,399
Impairment of oil and gas properties	27,134	43,990	—	—
Loss (gain) on sale of oil and gas properties	14,315	1,060	35,438	(155)
Total operating expenses	359,496	255,514	155,808	107,590
Operating income (loss)	(183,790)	(183)	10,822	116,031
Other income (expenses):				
Gain (loss) from derivative financial instruments	(5,356)	16,753	881	10,465
Gain on extinguishment of debt	189,052	—	—	—
Interest expense	(128,743)	(146,449)	(101,203)	(43,603)
Transaction costs	—	—	(2,866)	—
Other income	872	530	677	173
Total other income (expenses)	55,825	(129,166)	(102,511)	(32,965)
Income (loss) before income taxes	(127,965)	(129,349)	(91,689)	83,066
Benefit from (provision for) income taxes	(7,169)	17,944	(1,065)	(18,944)
Net income (loss)	$ (135,134)	$ (111,405)	$ (92,754)	$ 64,122
Net income (loss) per share – basic and diluted	$ (11.52)	$ (7.61)	$ (6.08)	$ 0.61
Weighted average shares outstanding:				
Basic	11,729	14,644	15,262	105,453
Diluted	11,729	14,644	15,262	105,459

The accompanying notes are an integral part of these statements.

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Common Shares	Common Stock- Par Value	Common Stock Warrants	Additional Paid-in Capital	Accumulated Earnings (Deficit)	Total
			(In thousands)			
Predecessor Company:						
Balance at January 1, 2016	9,544	$ 4,772	$ —	$ 504,670	$ (680,700)	$ (171,258)
Stock-based compensation	232	116	—	4,544	—	4,660
Income tax withholdings related to equity awards	(41)	(20)	—	(293)	—	(313)
Common stock issued for debt conversion	176	88	—	1,551	—	1,639
Common stock issued in exchange for debt	2,771	1,385	—	12,218	—	13,603
Common stock warrants issued	—	—	15,623	—	—	15,623
Common stock warrants exercised	1,256	628	(9,951)	9,336	—	13
Stock issuance costs	—	—	—	(102)	—	(102)
Net loss	—	—	—	—	(135,134)	(135,134)
Balance at December 31, 2016	13,938	6,969	5,672	531,924	(815,834)	(271,269)
Stock-based compensation	451	225	—	5,698	—	5,923
Income tax withholdings related to equity awards	(34)	(16)	—	(296)	—	(312)
Common stock issued for debt conversion	826	412	—	7,377	—	7,789
Common stock warrants exercised	247	124	(2,115)	1,993	—	2
Net loss	—	—	—	—	(111,405)	(111,405)
Balance at December 31, 2017	15,428	7,714	3,557	546,696	(927,239)	(369,272)
Stock-based compensation	623	311	—	3,601	—	3,912
Income tax withholdings related to equity awards	(53)	(26)	—	(343)	—	(369)
Common stock issued for debt conversion	2	1	—	28	—	29
Common stock warrants exercised	379	189	(3,247)	3,058	—	—
Net loss	—	—	—	—	(92,754)	(92,754)
Balance at August 13, 2018	16,379	$ 8,189	$ 310	$ 553,040	$ (1,019,993)	$ (458,454)
Successor Company:						
Successor common stock	16,379	$ 8,189	$ 310	$ 132,032	$ —	$ 140,531
Vesting of equity awards	1,029	514	—	8,312	—	8,826
Income tax withholdings related to equity awards	(547)	(272)	—	(4,423)	—	(4,695)
Jones contribution	88,571	44,286	—	315,902	—	360,188
Stock-based compensation	415	207	—	787	—	994
Stock issuance costs	—	—	—	(395)	—	(395)
Common stock warrants exercised and expired	24	12	(310)	298	—	—
Net income	—	—	—	—	64,122	64,122
Balance at December 31, 2018	105,871	$ 52,936	$ —	$ 452,513	$ 64,122	$ 569,571

The accompanying notes are an integral part of these statements.

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Predecessor			Successor
	Year Ended December 31, 2016	Year Ended December 31, 2017	For the Period from January 1, 2018 through August 13, 2018	For the Period from August 14, 2018 through December 31, 2018
	(In thousands, except per share amounts)			
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net income (loss)	$ (135,134)	$ (111,405)	$ (92,754)	$ 64,122
Adjustments to reconcile net loss to net cash provided by (used for) operating activities:				
Deferred and non-current income taxes	7,105	(18,080)	1,052	29,079
Loss (gain) on sale of oil and gas properties	14,315	1,060	35,438	(155)
Impairment of oil and gas properties	27,134	43,990	—	—
Dry hole costs, exploratory lease impairments and other exploration costs	84,144	—	—	—
Depreciation, depletion and amortization	141,487	123,557	68,032	53,944
(Gain) loss on derivative financial instruments	5,356	(16,753)	(881)	(10,465)
Cash settlements of derivative financial instruments	2,120	9,405	2,842	(5,579)
Gain on extinguishment of debt	(189,052)	—	—	—
Amortization of debt discount, premium and issuance costs	17,788	35,880	29,457	2,404
Interest paid in-kind	11,860	38,073	25,004	—
Stock-based compensation	4,660	5,923	3,912	994
Decrease (increase) in accounts receivable	(3,651)	(16,128)	2,834	(61,048)
Decrease (increase) in other current assets	169	(921)	337	(12,527)
Increase (decrease) in accounts payable and accrued expenses	(12,029)	80,013	10,462	41,533
Net cash provided by (used for) operating activities	(23,728)	174,614	85,735	102,302
CASH FLOWS FROM INVESTING ACTIVITIES:				
Acquisitions and capital expenditures	(57,424)	(180,481)	(150,106)	(169,786)
Advance payments for drilling costs	—	—	(3,692)	(5,644)
Proceeds from sales of oil and gas properties	27,855	1,528	103,593	13,796
Net cash used for investing activities	(29,569)	(178,953)	(50,205)	(161,634)
CASH FLOWS FROM FINANCING ACTIVITIES:				
Borrowings	—	8,000	865,577	450,000
Payments to retire debt	(3,397)	(8,000)	(49,679)	(1,291,352)
Jones contribution	—	—	—	40,736
Debt and equity issuance costs	(11,108)	—	(18,127)	(6,351)
Income tax withholdings related to equity awards	(313)	(312)	(369)	(4,695)
Common stock warrants exercised	13	2	—	—
Net cash provided by (used for) financing activities	(14,805)	(310)	797,402	(811,662)
Net increase (decrease) in cash and cash equivalents	(68,102)	(4,649)	832,932	(870,994)
Cash and cash equivalents, beginning of the year	134,006	65,904	61,255	894,187
Cash and cash equivalents, end of the year	$ 65,904	$ 61,255	$ 894,187	$ 23,193

The accompanying notes are an integral part of these statements.

(1) Summary of Significant Accounting Policies

Accounting policies used by Comstock Resources, Inc. and subsidiaries reflect oil and natural gas industry practices and conform to accounting principles generally accepted in the United States of America.

Basis of Presentation and Principles of Consolidation

Comstock Resources, Inc. and its subsidiaries are engaged in oil and natural gas exploration, development and production, and the acquisition of producing oil and natural gas properties. The Company's operations are primarily focused in Texas, Louisiana and North Dakota. The consolidated financial statements include the accounts of Comstock Resources, Inc. and its wholly owned or controlled subsidiaries (collectively, "Comstock" or the "Company"). All significant intercompany accounts and transactions have been eliminated in consolidation. The Company accounts for its undivided interest in oil and gas properties using the proportionate consolidation method, whereby its share of assets, liabilities, revenues and expenses are included in its financial statements. Net income (loss) and comprehensive income (loss) are the same in all periods presented.

Management of the Company has assessed the Company's financial condition, the current capital markets and its future plans given different scenarios of oil and natural gas prices and believes the Company has adequate liquidity to fund its operations for at least twelve months from the date of issuance of these financial statements, which is the requirement to be considered a going concern under generally accepted accounting principles. Management cannot predict how an extended period of low oil and natural gas prices will affect the Company's future operations and liquidity levels.

On August 14, 2018, Arkoma Drilling, L.P. and Williston Drilling, L.P. (collectively, the "Jones Partnerships") contributed certain oil and gas properties in North Dakota and Montana (the "Bakken Shale Properties") in exchange for 88,571,429 newly issued shares of common stock representing 84% of the Company's outstanding common stock (the "Jones Contribution"). The Jones Partnerships are wholly owned and controlled by Dallas businessman Jerry Jones and his children (collectively, the "Jones Group").

The Company assessed the Bakken Shale Properties to determine whether they meet the definition of a business under US generally accepted accounting principles, determining that they do not meet the definition of a business. As a result, the Jones Contribution is not being accounted for as a business combination. Upon the issuance of the shares of Comstock common stock, the Jones Group obtained control over Comstock through their ownership of the Jones Partnerships. Through the Jones Partnerships, the Jones Group owns a majority of the voting common stock as well as the ability to control the composition of the majority of the board of directors of Comstock. As a result of the change of control that occurred upon the issuance of the common stock, the Jones Group controls Comstock and, thereby, continues to control the Bakken Shale Properties.

Accordingly, the basis of the Bakken Shale Properties recognized by Comstock is the historical basis of the Jones Group. The historical cost basis of the Bakken Shale properties contributed was $397.6 million, which was comprised of $554.3 million of capitalized costs less $156.7 million of accumulated depletion, depreciation and amortization. The change in control of Comstock results in a new basis for Comstock as the Company has elected to apply pushdown accounting pursuant to ASC 805, Business Combinations. The new basis is pushed down to Comstock for financial reporting purposes, resulting in

Comstock's assets, liabilities and equity accounts being recognized at fair value upon the closing of the Jones Contribution.

References to "Successor" or "Successor Company" relate to the financial position and results of operations of the Company subsequent to August 13, 2018. Reference to "Predecessor" or "Predecessor Company" relate to the financial position and results of operations of the Company on or prior to August 13, 2018. The Company's consolidated financial statements and related footnotes are presented with a black line division which delineates the lack of comparability between amounts presented after August 13, 2018 and dates prior thereto.

The estimated fair value of Comstock's assets and liabilities and the resulting goodwill at the date of the transaction were as follows:

		(In thousands)
Fair Value of Comstock's common stock	$	149,357
Fair Value of Liabilities Assumed —		
Current Liabilities		180,452
Long-Term Debt		2,059,560
Deferred Income Taxes		63,708
Reserve for Future Abandonment Costs		4,440
Net Liabilities Assumed		2,308,160
Fair Value of Assets Acquired —		
Current Assets		936,026
Oil and Gas Properties		1,147,749
Other Property & Equipment		4,440
Income Taxes Receivable		19,086
Other Assets		2
Total Assets		2,107,303
Goodwill	$	350,214

The table above represents the preliminary allocation of fair value related to the assets acquired and the liabilities assumed based on the fair value of Comstock. Certain data necessary to complete the fair value allocation is not yet available or is in the process of being finalized, and includes, but is not limited to, final income tax returns. The Company expects to complete the purchase price allocation during the twelve month period following the closing of the Jones Contribution, during which time the value of the assets and liabilities, including goodwill, may be revised as appropriate.

Goodwill recognized is primarily attributable to the excess of the fair value of Comstock's common stock over the identifiable assets acquired net of liabilities assumed, measured in accordance with generally accepted accounting principles in the United States. The fair value of oil and gas properties, a Level 3 measurement, was determined using discounted cash flow valuation methodology. Key inputs to the valuation included average oil prices of $79.72 per barrel, average natural gas prices of $3.87 per thousand cubic feet and discount rates of 10% - 25%, based on reserve classification. The combination of the Bakken Shale Properties with Comstock's Haynesville shale properties results in a Company with adequate resources and liquidity to fully exploit its Haynesville/Bossier shale asset base and to continue to expand its opportunity set with future acquisitions and leasing activity in the basin.

Transaction-related costs (i.e., advisory, legal, accounting, valuation, other professional or consulting fees) totaling approximately $2.6 million are not included as a component of consideration transferred but are accounted for as expenses in the Predecessor Periods in which the costs were incurred and the services received. Costs incurred associated with the issuance of common stock have been accounted for as a reduction of additional paid-in capital.

The closing of the Jones Contribution triggered payment of an aggregate of $8.1 million including success fees to financial advisors and certain other fees under our licenses for technical data. These costs were contingent on the consummation of the transactions, all of which were interdependent and all of which had to close in order to meet the legal requirements of the contribution agreement. None of these fees would have been incurred otherwise. The Jones Contribution also caused a change in control, upon which restricted shares granted to employees and directors vested, and performance share units granted to executive officers vested at the maximum number of shares granted. The Company had previously recognized stock-based compensation expense of $7.2 million related to these restricted shares and performance share units. The Company did not recognize an expense for the remaining $11.9 million of unrecognized stock-based compensation expense. The change in control also resulted in an additional $0.5 million of other benefits to the Company's officers. The Company's accounting policy for any cost triggered by the consummation of the Jones Contribution was to recognize the cost when the Jones Contribution was consummated. Accordingly, unrecognized stock-based compensation expense has not been recorded in the Consolidated Statement of Operations for the Predecessor period since that statement depicts the results of operations just prior to consummation of the transaction. In addition, since the Successor period reflects the effects of push-down accounting, these costs have also not been recorded as an expense in the Successor period. These costs are being considered in the purchase accounting adjustments in arriving at the fair value of the liabilities assumed since they were incurred only in the event the transactions successfully closed, and they are not clearly identifiable to operations either prior to or subsequent to the Jones Contribution.

Under the terms of the Jones Contribution, April 1, 2018 was the effective date for allocation of revenues and expenses related to net cash of the Bakken Shale Properties, and Comstock received $40.7 million related to net cash flow from April 1, 2018 to August 13, 2018 from the Jones Partnerships which has been accounted as part of the Jones Contribution.

The financial statements are presented on the basis of the Bakken Shale Properties being contributed to Comstock in exchange for common stock of Comstock. Comstock is a corporation, which is treated as a taxable C corporation and thus is subject to federal and state income taxes. A deferred tax liability of approximately $77.9 million has been recognized related to the tax basis of the Bakken Shale Properties long-lived assets being less than the book basis in those assets. The recording of this deferred tax liability has been treated as an adjustment to additional paid-in capital in these financial statements. The change in control of Comstock results in a new basis for Comstock as the company is applying pushdown accounting pursuant to ASC 805, Business Combinations. The new basis is pushed down to Comstock for financial reporting purposes, resulting in Comstock's assets, liabilities and equity accounts being recognized at fair value upon the closing of the Jones Contribution. A deferred tax liability, net of valuation allowance of $52.4 million has been recognized related to the change in the basis for financial reporting purposes as compared to the tax basis of the historical Comstock assets.

The unaudited pro forma financial information presented below sets forth the Company's historical statements of operations for the periods indicated and gives effect to the Jones Contribution and the Company's debt refinancing transactions as if "push down" accounting had been applied as of January 1, 2017. Such information is presented for comparative purposes to the Consolidated Statements of Operations only and does not purport to represent what the Company's results of operations would actually have been had these transactions occurred on the date indicated or to project its results of operations for any future period or date.

	Pro Forma Year Ended December 31, 2017	Pro Forma Year Ended December 31, 2018 (1)
Revenues:		
Natural gas sales	$ 225,477	$ 303,220
Oil sales	224,816	245,684
Total oil and gas sales	450,293	548,904
Operating expenses:		
Production taxes	23,755	29,841
Gathering and transportation	17,538	22,352
Lease operating	59,359	56,811
Depreciation, depletion and amortization	192,680	170,209
General and administrative	26,137	27,415
Impairment of oil and gas properties	43,990	—
Loss on sale of oil and gas properties	1,060	35,283
Total operating expenses	364,519	341,911
Operating income	85,774	206,993
Other income (expenses):		
Gain (loss) from derivative financial instruments	16,753	11,346
Other income	530	850
Interest expense	(111,686)	(109,195)
Total other income (expenses)	(94,403)	(96,999)
Income (loss) before income taxes	(8,629)	109,994
Benefit from (provision for) income taxes	23,119	(27,543)
Net Income	$ 14,490	$ 82,451
Net income per share – basic and diluted	$ 0.14	$ 0.78
Weighted average shares outstanding –		
Basic	105,148	105,453
Diluted	105,610	105,459

(1) Excludes $2.6 million of transaction costs associated with the Jones Contribution.

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual amounts could differ from those estimates. Changes in the future estimated oil and natural gas reserves or the estimated future cash flows attributable to the reserves that are utilized for impairment analyses could have a significant impact on the future results of operations.

Concentration of Credit Risk and Accounts Receivable

Financial instruments that potentially subject the Company to a concentration of credit risk consist principally of cash and cash equivalents, accounts receivable and derivative financial instruments. The Company places its cash with high credit quality financial institutions and its derivative financial instruments with financial institutions and other firms that management believes have high credit ratings. Substantially all of the Company's accounts receivable are due from either purchasers of oil and gas or participants in oil and gas wells for which the Company serves as the operator. Generally, operators of oil and gas wells have the right to offset future revenues against unpaid charges related to operated wells. Oil and gas sales are generally unsecured. The Company's policy is to assess the collectability of its receivables based upon their age, the credit quality of the purchaser or participant and the potential for revenue offset. The Company has not had any significant credit losses in the past and believes its accounts receivable are fully collectible. Accordingly, no allowance for doubtful accounts has been provided.

Other Current Assets

Other current assets at December 31, 2017 and 2018 consist of the following:

	Predecessor As of December 31, 2017	Successor As of December 31, 2018
	(In thousands)	
Advance payments for drilling costs	$ —	$ 9,336
Production tax refunds receivable	1,409	1,453
Pipe and oil field equipment inventory	998	912
Other	338	2,128
	$ 2,745	$ 13,829

Fair Value Measurements

Certain accounts within the Company's consolidated balance sheets are required to be measured at fair value on a recurring basis. These include cash equivalents held in bank accounts and derivative financial instruments in the form of oil and natural gas price swap agreements. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. A three-level hierarchy is followed for disclosure to show the extent and level of judgment used to estimate fair value measurements:

Level 1 – Inputs used to measure fair value are unadjusted quoted prices that are available in active markets for the identical assets or liabilities as of the reporting date.

Level 2 – Inputs used to measure fair value, other than quoted prices included in Level 1, are either directly or indirectly observable as of the reporting date through correlation with market data, including quoted prices for similar assets and liabilities in active markets and quoted prices in markets that are not active. Level 2 also includes assets and liabilities that are valued using models or other pricing methodologies that do not require significant judgment since the input assumptions used in the models, such as interest rates and volatility factors, are corroborated by readily observable data from actively quoted markets for substantially the full term of the financial instrument.

Level 3 – Inputs used to measure fair value are unobservable inputs that are supported by little or no market activity and reflect the use of significant management judgment. These values are generally determined using pricing models for which the assumptions utilize management's estimates of market participant assumptions.

The Company's cash and cash equivalents valuation is based on Level 1 measurements. The Company's oil and natural gas price derivative financial instruments were not traded on a public exchange, and their value is determined utilizing a discounted cash flow model based on inputs that are readily available in public markets and, accordingly, the valuation of these derivative financial instruments is categorized as a Level 2 measurement. There are no financial assets or liabilities accounted for at fair value as of December 31, 2018 that are a Level 3 measurement.

As of December 31, 2018, the Company's other financial instruments, comprised solely of its long-term debt, had a carrying value of $1.3 billion and a fair value of $1.2 billion. As of December 31, 2018, the Company's fixed rate debt had a carrying value of $817.1 million and a fair value of $720.0 million. The fair market value of the Company's fixed rate debt was based on quoted prices as of December 31, 2018, a Level 2 measurement. The fair value of the floating rate debt outstanding at December 31, 2018 approximated its carrying value, a Level 2 measurement.

Property and Equipment

The Company follows the successful efforts method of accounting for its oil and gas properties. Costs incurred to acquire oil and gas leasehold are capitalized. Acquisition costs for proved oil and gas properties, costs of drilling and equipping productive wells, and costs of unsuccessful development wells are capitalized and amortized on an equivalent unit-of-production basis over the life of the remaining related oil and gas reserves. Equivalent units are determined by converting oil to natural gas at the ratio of one barrel of oil for six thousand cubic feet of natural gas. This conversion ratio is not based on the price of oil or natural gas, and there may be a significant difference in price between an equivalent volume of oil versus natural gas. The estimated future costs of dismantlement, restoration, plugging and abandonment of oil and gas properties and related facilities disposal are capitalized when asset retirement obligations are incurred and amortized as part of depreciation, depletion and amortization expense. Exploration expense includes geological and geophysical expenses and delay rentals related to exploratory oil and gas properties, costs of unsuccessful exploratory drilling and impairments of unproved properties. As of December 31, 2018, the unproved properties primarily relates to future drilling locations that were not included in proved undeveloped reserves. These future drilling locations are located on acreage where the reservoir is known to be productive but have been excluded from proved reserves due to uncertainty on whether the wells would be drilled within the next five years as required by SEC rules in order to be included in proved reserves. The costs of unproved properties are transferred to proved oil and gas properties when they are either drilled or they are reflected in proved undeveloped reserves and amortized on an equivalent unit-of-production basis. Costs associated with unevaluated exploratory acreage are periodically assessed for impairment on a property by property basis, and any impairment in value is included in exploration expense. During 2016, impairment charges of $84.1 million were recognized in exploration expense related to certain exploratory leases that the Company no longer expected to drill. Exploratory drilling costs are initially capitalized as unproved property but charged to expense if and when the well is determined not to have found commercial proved oil and gas reserves. Exploratory drilling costs are evaluated within a one-year period after the completion of drilling.

The Company periodically assesses the need for an impairment of the costs capitalized for its proved oil and gas properties. If impairment is indicated based on undiscounted expected future cash flows attributable to the property, then a provision for impairment is recognized to the extent that net capitalized costs exceed the estimated fair value of the property. The Company determines the fair values of its oil and gas properties using a discounted cash flow model and proved and risk-adjusted probable reserves. Significant Level 3 assumptions associated with the calculation of discounted future cash flows included in the cash flow model include management's outlook for oil and natural gas prices, future oil and natural gas production, production costs, capital expenditures, and the total proved and risk-adjusted probable oil and natural gas reserves expected to be recovered. Management's oil and natural gas price outlook is developed based on third-party longer-term price forecasts as of each measurement date. The expected future net cash flows are discounted using an appropriate discount rate in determining a property's fair value. The oil and natural gas prices used for determining asset impairments will generally differ from those used in the standardized measure of discounted future net cash flows because the standardized measure requires the use of an average price based on the first day of each month of the preceding year. Unproved properties are evaluated for impairment based upon the results of drilling, planned future drilling and the terms of the oil and gas leases.

In 2017, the Company recognized an impairment of $43.8 million to adjust the carrying value of Comstock's South Texas oil properties which were classified as held for sale at December 31, 2017. In 2016, the Company recognized impairments of $27.1 million on certain of its oil and gas properties.

The Company's estimates of undiscounted future net cash flows attributable to its oil and gas properties may change in the future. The primary factors that may affect estimates of future cash flows include future adjustments, both positive and negative, to proved and appropriate risk-adjusted probable oil and natural gas reserves, results of future drilling activities, future prices for oil and natural gas, and increases or decreases in production and capital costs. As a result of these changes, there may be impairments in the carrying values of our oil and gas properties.

Other property and equipment consists primarily of computer equipment, furniture and fixtures and an airplane which are depreciated over estimated useful lives ranging from three to 31½ years on a straight-line basis.

Goodwill

The Company has goodwill of $350.2 million as of December 31, 2018 that was recorded in connection with the Jones Contribution. Goodwill represents the excess of purchase price over fair value of net tangible and identifiable intangible assets. The Company is not required to amortize goodwill as a charge to earnings; however, the Company is required to conduct an annual review of goodwill for impairment. The Company performs annual reviews of goodwill.

The Company determines the potential for impairment of its goodwill by initially preparing a qualitative fair value assessment of its business value. In performing this qualitative assessment, the Company examines relevant events and circumstances that could have a negative effect on its business, including macroeconomic conditions, industry and market conditions (including current commodity price), earnings and cash flows, overall financial performance and other relevant entity specific events.

If the qualitative assessment indicates that it is more likely than not that Comstock's business is impaired, a quantitative analysis would be performed to assess the Company's fair value and to determine the amount of impairment, if any, that requires recognition. When performing a quantitative impairment assessment of goodwill, fair value is determined based on a combination of (i) recent market transactions, where available; and (ii) projected discounted cash flows (an income approach). Under the market approach, fair value would be estimated by a comparison to similar businesses whose securities are actively traded in the public market. This requires Comstock's management to make certain judgments, including the selection of comparable companies, comparable recent company asset transactions, transaction premiums and selected financial metrics. Under the income approach, fair value is based on the present value of expected future cash flows. The income approach is dependent on a number of factors including estimates of forecasted revenues, estimates of future operating, administrative and capital costs adjusted for inflation, projected reserves quantities, the probability of success for future exploration for and development of proved and unproved reserves, discount rates and other variables. Future cash flows are discounted using discount factors applied by Comstock when assessing oil and gas acquisition opportunities and which the Company believes provide a fair market value of its business. Negative revisions of estimated reserves quantities, sustained decreases in crude oil or natural gas prices, increases in future cost estimates, or divestitures could lead to reductions in expected future cash flows that would indicate potential impairment of all or a portion of goodwill in future periods.

If the carrying value of goodwill exceeds the fair value calculated using the quantitative approach, an impairment charge would be recorded for the difference between fair value and carrying value. If oil or natural gas prices decrease, drilling efforts are unsuccessful or the Company’s market capitalization declines, it is reasonably possible that additional impairments would need to be recognized.

Accrued Expenses

Accrued expenses at December 31, 2017 and 2018 consist of the following:

	Predecessor	Successor
	As of December 31, 2017	As of December 31, 2018
	(In thousands)	
Accrued interest payable	$ 21,277	$ 35,461
Accrued drilling costs	5,874	17,920
Accrued transportation costs	3,269	4,632
Accrued employee compensation	6,449	6,045
Accrued lease operating expenses	68	2,130
Asset retirement obligation – assets held for sale	4,557	—
Other	961	1,898
	$ 42,455	$ 68,086

Reserve for Future Abandonment Costs

The Company's asset retirement obligations relate to future plugging and abandonment costs of its oil and gas properties and related facilities disposal. The Company records a liability in the period in which an asset retirement obligation is incurred, in an amount equal to the estimated fair value of the obligation that is capitalized. Thereafter, this liability is accreted up to the final retirement cost. Accretion of the discount is included as part of depreciation, depletion and amortization in the accompanying consolidated statements of operations.

The following table summarizes the changes in the Company's total estimated liability:

	Predecessor		Successor
	Year Ended December 31, 2017	For the Period from January 1, 2018 through August 13, 2018	For the Period from August 14, 2018 through December 31, 2018
		(In thousands)	
Reserve for future abandonment costs at beginning of the year	$ 15,804	$ 10,407	$ 4,683
New wells placed on production	7	17	50
Changes in estimates and timing	(1,260)	—	270
Liabilities settled	(77)	(87)	—
Assets held for sale	(4,557)	—	—
Asset divestitures	(320)	—	—
Accretion expense	810	346	133
Reserve for future abandonment costs at end of the year	$ 10,407	$ 10,683	$ 5,136

Stock-based Compensation

The Company has stock-based employee compensation plans under which stock awards, comprised primarily of restricted stock and performance share units, are issued to employees and non-employee directors. The Company follows the fair value based method in accounting for equity-based compensation. Under the fair value based method, compensation cost is measured at the grant date based on the fair value of the award and is recognized on a straight-line basis over the award vesting period.

Segment Reporting

The Company presently operates in one business segment, the exploration and production of oil and natural gas.

Derivative Financial Instruments and Hedging Activities

The Company accounts for derivative financial instruments (including derivative instruments embedded in other contracts) as either an asset or liability measured at its fair value. Changes in the fair value of derivatives are recognized currently in earnings unless specific hedge accounting criteria are met. The Company estimates fair value based on a discounted cash flow model. The fair value of derivative contracts that expire in less than one year are recognized as current assets or liabilities. Those that expire in more than one year are recognized as long-term assets or liabilities.

Major Purchasers

In 2016, the Company had four major purchasers of its oil and natural gas production that represented 42%, 17%, 14% and 12% of its total oil and gas sales. In 2017, the Company had four major purchasers of its oil and natural gas production that accounted for 34%, 17%, 16% and 15% of its total oil and gas sales. In the Predecessor Period January 1, 2018 through August 13, 2018 the Company had three major purchasers of its oil and gas production that accounted for 33%, 22% and 20% of its total oil and natural gas sales. During the Successor Period August 14, 2018 through December 31, 2018, the Company had two major purchasers of its oil and natural gas production that accounted for 32% and 18% of its total oil and natural gas sales. The loss of any of these purchasers would not have a material adverse effect on the Company as there is an available market for its oil and natural gas production from other purchasers.

Revenue Recognition and Gas Balancing

On January 1, 2018, the Company adopted Financial Accounting Standards Board ("FASB") Accounting Standards Update ("ASU") 2014-09, *Revenue from Contracts with Customers (Topic 606)* ("ASU 2014-09"). Comstock adopted this standard using the modified retrospective method of adoption, and it applied the ASU only to contracts that were not completed as of January 1, 2018. Upon adoption, there were no adjustments to the opening balance of equity.

Comstock produces oil and natural gas and reports revenues separately for each of these two primary products in its statements of operations. Revenues are recognized upon the transfer of produced volumes to the Company's customers, who take control of the volumes and receive all the benefits of ownership upon delivery at designated sales points. Payment is reasonably assured upon delivery of production. All sales are subject to contracts that have commercial substance, contain specific pricing terms, and define the enforceable rights and obligations of both parties. These contracts typically provide for cash settlement within 25 days following each production month and are cancellable upon 30 days' notice by either party. Prices for sales of oil and natural gas are generally based upon terms that are common in the oil and gas industry, including index or spot prices, location and quality differentials, as well as market supply and demand conditions. As a result, prices for oil and natural gas routinely fluctuate based on changes in these factors. Each unit of production (barrel of crude oil and thousand cubic feet of natural gas) represents a separate performance obligation under the Company's contracts since each unit has economic benefit on its own and each is priced separately according to the terms of the contracts.

Comstock has elected to exclude all taxes from the measurement of transaction prices, and its revenues are reported net of royalties and exclude revenue interests owned by others because the Company acts as an agent when selling crude oil and natural gas, on behalf of royalty owners and working interest owners. Revenue is recorded in the month of production based on an estimate of the Company's share of volumes produced and prices realized. The Company recognizes any differences between estimates and actual amounts received in the month when payment is received. Historically, differences between estimated revenues and actual revenue received have not been significant. The amount of oil or natural gas sold may differ from the amount to which the Company is entitled based on its revenue interests in the properties. The Company did not have any significant imbalance positions at December 31, 2017 or 2018. Sales of oil and natural gas generally occur at or near the wellhead. When sales of oil and gas occur at locations other than the wellhead, the Company accounts for costs incurred to transport the production to the delivery point as gathering and transportation expenses. The Company has recognized accounts receivable of $87.6 million as of December 31, 2018 from customers for contracts where performance obligations have been satisfied and an unconditional right to consideration exists. Accounts receivable for oil and gas sales at December 31, 2018 increased from accounts receivable at December 31, 2017 mainly due to our higher production of natural gas and oil and natural gas production from the Bakken shale properties that were contributed to the Company in August, 2018.

General and Administrative Expenses

General and administrative expenses are reported net of reimbursements of overhead costs that are received from working interest owners of the oil and gas properties operated by the Company of $12.4 million, $11.7 million, $8.5 million and $4.5 million in 2016, 2017, for the Predecessor Period from January 1, 2018 through August 13, 2018, and for the Successor Period from August 14, 2018 through December 31, 2018, respectively.

Income Taxes

The Company accounts for income taxes using the asset and liability method, whereby deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax basis, as well as the tax consequences attributable to the future utilization of existing net operating loss and other carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that the change in rate is enacted.

Earnings Per Share

Unvested share-based payment awards containing nonforfeitable rights to dividends are considered to be participating securities and included in the computation of basic and diluted earnings per share pursuant to the two-class method. Performance share units ("PSUs") represent the right to receive a number of shares of the Company's common stock that may range from zero to up to two times the number of PSUs granted on the award date based on the achievement of certain performance measures during a performance period. The number of potentially dilutive shares related to PSUs is based on the number of shares, if any, which would be issuable at the end of the respective period, assuming that date was the end of the contingency period. The treasury stock method is used to measure the dilutive effect of PSUs. Unexercised common stock warrants represent the right to convert the warrants into common stock at an exercise price of $0.01 per share. The treasury stock method is used to measure the dilutive effect of unexercised common stock warrants. The shares that would be issuable upon exercise of the conversion rights contained in the Company's convertible debt for each period were based on the if-converted method for computing potentially dilutive shares of common stock that could be issued upon conversion. None of the Company's participating securities participate in losses and as such are excluded from the computation of basic earnings per share during periods of net losses.

Basic and diluted earnings per share were determined as follows:

	Successor		
	For the Period from August 14, 2018 through December 31, 2018		
	Income	Shares	Per Share
	(In thousands, except per share amounts)		
Net income attributable to common stock	$ 64,122		
Income allocable to unvested restricted shares	(248)		
Basic income attributable to common stock	63,874	105,453	$ 0.61
Effect of Dilutive Securities:			
Stock warrants	—	6	
Diluted income attributable to common stock	63,874	105,459	$ 0.61

	Predecessor								
	Twelve Months Ended December 31, 2016			Twelve Months Ended December 31, 2017			For the Period January 1, 2018 through August 13, 2018		
	Loss	Shares	Per Share	Loss	Shares	Per Share	Loss	Shares	Per Share
	(In thousands, except per share amounts)								
Basic and diluted net loss attributable to common stock	$ (135,134)	11,729	$ (11.52)	$ (111,405)	14,644	$ (7.61)	$ (92,754)	15,262	$ (6.08)

Basic and diluted per share amounts are the same for the Predecessor periods due to the net loss in those periods.

Shares of unvested restricted stock are included in common stock outstanding as such shares have a nonforfeitable right to participate in any dividends that might be declared and have the right to vote. Weighted average shares of unvested restricted stock included in common stock outstanding were as follows:

			Predecessor	Successor
	2016	2017	For the Period from January 1, 2018 through August 13, 2018	For the Period from August 14, 2018 through December 31, 2018
	(In thousands)			
Unvested restricted stock	344	612	839	410

All stock options, unvested PSUs, warrants exercisable into common stock and contingently issuable shares related to the convertible debt that were anti-dilutive to earnings and excluded from weighted average shares used in the computation of earnings per share were as follows:

			Predecessor	Successor
	2016	2017	For the Period from January 1, 2018 through August 13, 2018	For the Period from August 14, 2018 through December 31, 2018
	(In thousands)			
Weighted average PSUs	136	274	476	328
Weighted average grant date fair value per unit	$22.17	$17.12	$13.83	$12.93
Weighted average stock options	11	—	—	—
Weighted average exercise price per share	$166.10	—	—	—
Weighted average warrants for common stock	337	463	142	—
Weighted average exercise price per share	$0.01	$0.01	$0.01	—
Weighted average contingently convertible shares	11,574	37,046	39,819	—
Weighted average conversion price per share	$12.32	$12.32	$12.32	—

Supplementary Information With Respect to the Consolidated Statements of Cash Flows

For the purpose of the consolidated statements of cash flows, the Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Cash payments made for interest and income taxes were as follows:

					Predecessor		Successor	
	Year Ended December 31,				For the Period from January 1, 2018 through August 13, 2018		For the Period from August 14, 2018 through December 31, 2018	
	2016		2017					
			(In thousands)					
Interest payments	$	105,449	$	73,941	$	36,187	$	8,042
Income tax payments	$	—	$	3	$	2	$	—

The Company paid $11.9 million, $38.1 million and $25.0 million of interest in-kind on its convertible notes in 2016, 2017 and the Predecessor Period from January 1, 2018 through August 13, 2018, respectively.

Recent accounting pronouncements

In January 2017, the FASB issued Accounting Standards Update No. 2017-04 (ASU 2017-04) "Intangibles-Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment." ASU 2017-04 eliminates step two of the goodwill impairment test and specifies that goodwill impairment should be measured by comparing the fair value of a reporting unit with its carrying amount. ASU 2017-04 is effective for annual or interim goodwill impairment tests performed in fiscal years beginning after December 15, 2019 and early adoption is permitted. The Company has initially recognized goodwill in its financial statements for the quarter ended September 30, 2018 and it will assess the impact of ASU 2017-04 on its financial statements when it performs its annual impairment assessments following adoption of this standard in 2020.

In February 2016, the FASB issued ASU No. 2016-02, Leases ("ASU 2016-02"). ASU 2016-02 requires lessees to include most leases on their balance sheets, but recognize lease costs in their financial statements in a manner similar to accounting for leases prior to ASC 2016-02. ASU 2016-02 is effective for annual periods ending after December 15, 2018 and interim periods thereafter. The Company is adopting ASC 2016-02 beginning January 1, 2019; Comstock is using the modified retrospective method of adoption for this new standard and is applying several of the available transition practical expedients as part of adoption. The adoption of ASC 2016-02 is not expected to have a significant effect on the Company's results of operations, liquidity or financial position.

(2) Acquisitions and Dispositions of Oil and Gas Properties

In December 2016, the Company sold certain of its natural gas properties located in South Texas realizing net proceeds of $25.8 million. The Company recognized a loss on the sale of these assets in 2016 totaling $13.4 million and an impairment of $20.8 million in the first quarter of 2016 to adjust the carrying value of these assets to their fair value. The Company also sold certain other oil and gas properties during 2016 for total proceeds of $2.1 million. The Company recognized a loss of $1.6 million on these divestitures.

In October 2017, the Company adopted a plan of sale for its Eagle Ford shale oil properties located in South Texas. The Company recognized an impairment of $43.8 million in the fourth quarter of 2017 to adjust the carrying value of these assets to their fair value less costs to sell. The Company determined the fair value based on estimated discounted future net cash flows of the properties appropriately risk adjusted based on indication of values received from potential acquirers in a competitive bid process. The asset retirement liability of $4.6 million associated with these assets was reclassified to current liabilities as of December 31, 2017. In April 2018, Comstock completed the sale of its producing Eagle Ford shale oil and gas properties for $106.4 million and retained the undeveloped acreage. The Company recognized a loss on sale of these properties of $32.7 million during the Predecessor Period from January 1, 2018 through August 13, 2018.

Results of operations for the properties that were sold and classified as held for sale in 2016, 2017 and during the Predecessor Period from January 1 through August 13, 2018 were as follows:

	Predecessor		
	Year Ended December 31,		For the Period from January 1, 2018 through August 13, 2018
	2016	2017	
	(In thousands)		
Total oil and gas sales	$ 63,303	$ 48,949	$ 17,747
Total operating expenses(1)	(80,467)	(44,861)	(6,134)
Operating income (loss)	$ (17,164)	$ 4,088	$ 11,613

(1) Includes direct operating expenses, depreciation, depletion and amortization and exploration expense. Excludes interest expense, general and administrative expenses and depreciation, depletion and amortization expense subsequent to the date the assets were designated as held for sale.

In January 2016, the Company exchanged certain oil and gas properties with another operator in a non-monetary exchange. Under the exchange, the Company received 3,637 net acres in DeSoto Parish, Louisiana, prospective for the Haynesville shale, including four producing wells (3.5 net). The Company exchanged 2,547 net acres in Atascosa County, Texas, including seven producing wells (5.3 net) for the Haynesville shale properties. The Company recognized a gain of $0.7 million on this transaction which was included in the loss on sale of oil and gas properties for the year ended December 31, 2016.

In 2017, the Company entered agreements to jointly develop certain acreage prospective for the Haynesville shale in Louisiana and Texas with USG Properties Haynesville, LLC ("USG"). As of December 31, 2017, USG had acquired approximately 6,300 net acres prospective for Haynesville shale development for the joint development program primarily in Caddo Parish, Louisiana. The Company operates wells drilled on USG's acreage and has the right to acquire a 25% working interest in the first twelve wells drilled on the acreage and 40% for all subsequent wells by reimbursing USG for the attributable acreage costs of the wells being drilled. USG is also participating in a Haynesville shale drilling program on approximately 5,700 acres of Comstock's acreage in Harrison County, Texas. Under the terms of the participation agreements, Comstock will receive $1.1 million for 50% of Comstock's interest for each location for acreage and infrastructure related to each well location, with $400,000 of that amount being paid only if each well meets or exceeds established production targets. Comstock also receives $80,000 for each well drilled as consideration for the Company's services managing the joint development program in addition to customary operating fees for each well drilled.

On September 21, 2018, the Company entered into a joint development venture with an affiliate of USG by contributing its undeveloped Eagle Ford shale acreage. Under the joint development venture, Comstock can participate in drilling wells on the undeveloped acreage and can participate in any in-fill wells or refracs of existing wells on acreage owned by the joint venture partner. Comstock subsequently sold a portion of the undeveloped acreage in the joint venture for proceeds of $13.7 million in September 2018.

On July 31, 2018, the Company acquired oil and gas properties in North Louisiana and Texas for $41.5 million. These properties included 22,559 acres (12,085 net) and 114 (27.8 net) producing natural gas wells, 47 (14.6 net) of which produce from the Haynesville shale.

On August 14, 2018, as part of the Jones Contribution, the strategic drilling venture previously entered into by the Company and Arkoma Drilling, LP was terminated and Comstock re-acquired working interests in wells drilled under the joint venture for $17.9 million representing the costs paid by Arkoma Drilling, LP.

On December 19, 2018, the Company entered into an agreement to acquire an 88% interest in the Haynesville shale rights covering 6,149 gross acres (5,301 net) in Harrison and Panola counties, Texas. The Company will pay $20.5 million over a four year period by providing a 12% interest in each well drilled by Comstock on the acreage. Comstock has identified 33 (22.7 net) potential drilling locations on this acreage.

(3) Oil and Gas Producing Activities

Set forth below is certain information regarding the aggregate capitalized costs of oil and gas properties and costs incurred by the Company for its oil and gas property acquisition, development and exploration activities:

Capitalized Costs

	Predecessor As of December 31, 2017	Successor As of December 31, 2018
	(In thousands)	
Proved properties:		
Leasehold costs	$ 491,507	$ 1,010,987
Wells and related equipment and facilities	2,140,243	671,177
Accumulated depreciation depletion and amortization	(2,032,927)	(210,452)
	598,823	1,471,712
Unproved properties	—	191,929
	$ 598,823	$ 1,663,641

Costs Incurred

	For the Years Ended December 31, 2016	For the Years Ended December 31, 2017	Predecessor: For the Period from January 1, 2018 through August 13, 2018	Successor: For the Period from August 14, 2018 through December 31, 2018
	(In thousands)			
Proved property acquisitions	$ —	$ —	$ 39,323	$ 21,013
Development costs	58,587	177,432	107,559	164,393
Exploration costs	—	—	—	—
	$ 58,587	$ 177,432	$ 146,882	$ 185,406

(4) Long-term Debt

Long-term debt is comprised of the following:

	Predecessor As of December 31, 2017	Successor As of December 31, 2018
	(In thousands)	
10% Senior Secured Toggle Notes due 2020:		
Principal	$ 697,195	$ —
Discount, net of amortization	(8,901)	—
7¾% Convertible Second Lien PIK Notes due 2019:		
Principal	284,442	—
Accrued interest payable in kind	5,572	—
Discount, net of amortization	(38,748)	—
9½% Convertible Second Lien PIK Notes due 2020:		
Principal	187,062	—
Accrued interest payable in kind	817	—
Discount, net of amortization	(31,844)	—
10% Senior Notes due 2020:		
Principal	2,805	—
7¾% Senior Notes due 2019:		
Principal	17,959	—
Premium, net of amortization	65	—
9½% Senior Notes due 2020:		
Principal	4,860	—
Discount, net of amortization	(70)	—
9¾% Senior Notes due 2026:		
Principal	—	850,000
Discount, net of amortization	—	(32,934)
Bank Credit Facility:		
Principal	—	450,000
Debt issuance costs, net of amortization	(10,685)	(22,703)
	$ 1,110,529	$ 1,244,363

The premium and discount on the senior notes are being amortized over the lives of the senior notes using the effective interest rate method. Issuance costs are amortized over the lives of the senior notes on a straight-line basis which approximates the amortization that would be calculated using an effective interest rate method.

The following table summarizes Comstock's principal amount of debt as of December 31, 2018 by year of maturity:

	2019	2020	2021	2022	2023	Thereafter	Total
				(In thousands)			
Bank credit facility	$ —	$ —	$ —	$ —	$ 450,000	$ —	$ 450,000
9¾% Senior Notes Due 2026	$ —	$ —	$ —	$ —	$ —	$ 850,000	$ 850,000
	$ —	$ —	$ —	$ —	$ 450,000	$ 850,000	$ 1,300,000

In connection with the Jones Contribution, the Company completed a series of refinancing transactions to retire all of its other then-outstanding senior secured and unsecured notes.

On August 3, 2018, the Company issued $850.0 million of new senior notes for proceeds of $815.9 million. Interest on the notes is payable on February 15 and August 15 at an annual rate of 9¾% and the notes mature on August 15, 2026.

On August 14, 2018, the Company entered into a new bank credit facility with Bank of Montreal, as administrative agent, and the participating banks which matures on August 14, 2023. The bank credit facility is subject to a borrowing base of $700.0 million which is re-determined on a semi-annual basis and upon the occurrence of certain other events. As of December 31, 2018, there were $450.0 million of borrowings outstanding under the revolving credit facility. Borrowings under the bank credit facility are secured by substantially all of the assets of the Company and its subsidiaries, and bear interest at the Company's option, at either LIBOR plus 2.0% to 3.0% or a base rate plus 1.0% to 2.0%, in each case depending on the utilization of the borrowing base. The Company also pays a commitment fee of 0.375% to 0.5% on the unused borrowing base. The bank credit facility places certain restrictions upon the Company's, and its restricted subsidiaries', ability to, among other things, incur additional indebtedness, pay cash dividends, repurchase common stock, make certain loans, investments and divestitures and redeem the new senior notes. The only financial covenants are the maintenance of a leverage ratio of less than 4.0 to 1.0 and a current ratio of at least 1.0 to 1.0. The Company was in compliance with the covenants as of December 31, 2018.

(5) Commitments and Contingencies

Commitments

The Company rents office space and other facilities under noncancelable operating leases. Rent expense for the Predecessor Period from January 1, 2018 through August 13, 2018 and for the Successor Period from August 14, 2018 through December 31, 2018 was $1.0 million and $0.6 million, respectively. Rent expense for the years ended December 31, 2016 and 2017 was $1.5 million and $1.6 million, respectively. Minimum future payments under the leases at December 31, 2018 are as follows:

		(In thousands)
2019	$	1,560
2020		1,560
2021		1,560
2022		—
2023		—
	$	4,680

The Company has entered into natural gas transportation and treating agreements through July 2019. Maximum commitments under these transportation agreements as of December 31, 2018 totaled $0.7 million. As of December 31, 2018, the Company had contracted for contract drilling services through September 2019 of $17.0 million.

Contingencies

From time to time, the Company is involved in certain litigation that arises in the normal course of its operations. The Company records a loss contingency for these matters when it is probable that a liability has been incurred and the amount of the loss can be reasonably estimated. The Company does not believe the resolution of these matters will have a material effect on the Company's financial position, results of operations or cash flows and no material amounts are accrued relative to these matters at December 31, 2017 or 2018.

(6) Stockholders' Equity

The authorized capital stock of the Company consists of 155 million shares of common stock, $0.50 par value per share, and 5 million shares of preferred stock, $10.00 par value per share. The preferred stock may be issued in one or more series, and the terms and rights of such stock will be determined by the Board of Directors. There were no shares of preferred stock outstanding at December 31, 2017 or 2018.

In 2016 and 2017, holders of the Company's convertible notes converted $2.1 million and $9.9 million of principal amount of the notes into 176,175 and 826,327 shares of common stock, respectively.

The Company issued warrants to acquire 1,917,342 shares of common stock for $0.01 per share in connection with a debt exchange completed in 2016. During 2017 and 2018, warrants were exercised for 1,502,255 and 402,708 shares of common stock, respectively, and 11,955 warrants expired without being exercised on September 7, 2018.

(7) Stock-based Compensation

The Company grants restricted shares of common stock and performance share units to key employees and directors as part of their compensation under the 2009 Long-term Incentive Plan. Future awards of performance share units, restricted stock grants or other equity awards are available under the stockholder approved 2009 Long-term Incentive Plan for 152,908 shares of common stock.

Stock-based compensation expense is included in general and administrative expenses. During 2016, 2017, and for the Predecessor Period from January 1, 2018 through August 13, 2018 the Company had $4.7 million, $5.9 million and $3.9 million, respectively, in stock-based compensation expense. For the Successor Period from August 14, 2018 through December 31, 2018, the Company had $1.0 million in stock-based compensation expense.

Restricted Stock

The fair value of restricted stock grants is amortized over the vesting period, generally one to three years, using the straight-line method. The fair value of each restricted share on the date of grant is equal to the market price of a share of the Company's stock.

A summary of restricted stock activity is presented below:

	Number of Restricted Shares	Weighted Average Grant Price
Predecessor Company:		
Outstanding at January 1, 2018	619,867	$11.14
Granted	546,027	$8.51
Shares issued for PSUs earned	85,987	—
Vested	(339,032)	$11.01
Forfeitures	(8,668)	$9.66
Outstanding at August 13, 2018	904,181	$8.43
Vested with the Jones Contribution	(904,181)	$8.43
Successor Company:		
Granted	422,545	$8.70
Forfeitures	(8,000)	$8.70
Outstanding at December 31, 2018	414,545	$8.70

The per share weighted average fair value of restricted stock grants in 2016 and 2017 was $5.46 and $11.11, respectively. The fair value of restricted stock which vested in 2016 and 2017 was $1.3 million and $1.7 million, respectively. Compensation expense recognized for restricted stock grants was $3.4 million, $3.9 million for the Predecessor years ended December 31, 2016 and 2017, respectively.

The per share weighted average fair value of restricted stock grants during the Predecessor Period from January 1, 2018 through August 13, 2018 was $8.51. The fair value of restricted stock which vested during the Predecessor Period from January 1, 2018 through August 13, 2018 was $2.7 million and compensation expense recognized for restricted stock was $2.3 million during this period. The change of control that occurred due to the Jones Contribution resulted in the vesting of all then outstanding restricted stock grants which had a fair value of $7.8 million.

The per share weighted average fair value of restricted stock grants for the Successor Period from August 14, 2018 through December 31, 2018 was $8.70. No restricted shares vested during the Successor Period from August 14, 2018 through December 31, 2018. Compensation expense recognized for restricted stock was $0.5 million for the Successor Period from August 14, 2018 through December 31, 2018. Total unrecognized compensation cost related to unvested restricted stock grants of $3.2 million as of December 31, 2018 is expected to be recognized over a period of 2.6 years.

Performance Share Units

The Company issues PSUs as part of its long-term equity incentive compensation. PSU awards can result in the issuance of common stock to the holder if certain performance criteria is met during a performance period. The performance periods consist of one to three years. The performance criteria for the PSUs are based on the Company's annualized total stockholder return ("TSR") for the performance period as compared with the TSR of certain peer companies for the performance period. The costs associated with PSUs are recognized as general and administrative expense over the performance periods of the awards.

The fair value of PSUs was measured at the grant date using the Geometric Brownian Motion Model ("GBM Model"). Significant assumptions used in this simulation include the Company's expected volatility and a risk-free interest rate based on U.S. Treasury yield curve rates with maturities consistent with the vesting periods, as well as the volatilities for each of the Company's peers. Assumptions regarding volatility included the historical volatility of each company's stock and the implied volatilities of publicly traded stock options.

Significant assumptions used to value PSUs included:

	Predecessor			Successor
	For the Years Ended December 31,		For the Period from January 1, 2018 through August 13, 2018	For the Period from August 14, 2018 through December 31, 2018
	2016	2017		
Risk free interest rate	0.9%	1.6%	2.32%	2.70%
Range of implied volatility:				
Minimum	47%	37%	42%	30%
Maximum	92%	134%	146%	88%

The fair value of PSUs is amortized over the vesting period of one to three years, using the straight-line method. The final number of shares of common stock issued may vary depending upon the performance multiplier, and can result in the issuance of zero to 829,090 shares of common stock based on the achieved performance ranges from zero to two.

A summary of PSU activity is presented below:

	Number of PSUs	Weighted Average Grant Price
Predecessor Company:		
Outstanding at January 1, 2018	281,800	$17.12
Granted	360,801	$12.52
Unearned	(42,278)	$18.07
PSUs earned	(85,987)	$17.06
Outstanding at August 13, 2018	514,336	$13.83
Vested with the Jones Contribution	(514,336)	$13.83
Successor Company:		
Granted	335,545	$12.93
Outstanding at December 31, 2018	335,545	$12.93

In 2016, the Company granted 60,015 PSUs with a grant date fair value of $0.4 million, or $7.00 per unit. In 2017, the Company granted 241,814 PSUs with a grant date fair value of $4.4 million, or $18.17 per unit. Total compensation expense recognized for PSUs was $1.3 million and $2.0 million for the years ended December 31, 2016 and 2017, respectively.

During the Predecessor Period from January 1, 2018 through August 13, 2018, the Company granted 360,801 PSUs with a grant date fair value of $4.5 million, or $12.52 per unit. Total compensation expense recognized for PSUs for the Predecessor Period from January 1, 2018 through August 13, 2018 was $1.6 million. 85,987 PSUs were earned and converted into restricted stock during the Predecessor Period from January 1, 2018 through August 13, 2018.

The change of control that occurred due to the Jones Contribution resulted in the vesting of all then outstanding performance share units at the maximum amount that could be earned, and a total of 1,028,672 shares of common stock were issued related to the earned PSUs with a fair value of $8.8 million.

During the Successor Period from August 14, 2018 through December 31, 2018, the company granted 335,545 PSUs with a grant date for value of $4.3 million, or $12.93 per unit. As of December 31, 2018, there was $3.8 million of total unrecognized expense related to PSUs, which is being amortized through August, 2021. Total compensation expense recognized for PSUs for the Successor Period from August 14, 2018 through December 31, 2018 was $0.5 million.

(8) Retirement Plan

The Company has a 401(k) profit sharing plan which covers all of its employees. At its discretion, Comstock may match the employees' contributions to the plan. Matching contributions to the plan were $758,000, $761,000, $508,000 and $252,000 for the years ended December 31, 2016, 2017, the Predecessor Period from January 1, 2018 through August 13, 2018 and the Successor Period from August 14, 2018 through December 31, 2018, respectively.

(9) Income Taxes

Deferred income taxes are provided to reflect the future tax consequences or benefits of differences between the tax basis of assets and liabilities and their reported amounts in the financial statements using enacted tax rates. The following is an analysis of the consolidated income tax provision (benefit):

	Predecessor			Successor
	For the Years Ended December 31,		For the Period from January 1, 2018 through August 13, 2018	For the Period from August 14, 2018 through December 31, 2018
	2016	2017		
		(In thousands)		
Current - Federal	$ —	$ (19,086)	$ —	$ (1,349)
- State	64	136	13	82
Deferred - Federal	—	—	2,412	16,406
- State	7,105	1,006	(1,360)	3,805
	$ 7,169	$ (17,944)	$ 1,065	$ 18,944

In recording deferred income tax assets, the Company considers whether it is more likely than not that its deferred income tax assets will be realized in the future. The ultimate realization of deferred income tax assets is dependent upon the generation of future taxable income during the periods in which those deferred income tax assets would be deductible. The Company believes that after considering all the available objective evidence, historical and prospective, with greater weight given to historical evidence, management is not able to determine that it is more likely than not that all of its deferred tax assets will be realized. As a result, the Company established valuation allowances for its deferred tax assets and U.S. federal and state net operating loss carryforwards that are not expected to be utilized due to the uncertainty of generating taxable income prior to the expiration of the carryforward periods. The Company will continue to assess the valuation allowances against deferred tax assets considering all available information obtained in future periods.

The Tax Cuts and Jobs Act, which was enacted on December 22, 2017, reduced the corporate income tax rate effective January 1, 2018 from 35% to 21%. Among the other significant tax law changes that potentially affect the Company are the elimination of the corporate alternative minimum tax ("AMT"), changes that require operating losses incurred in 2018 and beyond be carried forward indefinitely with no carryback up to 80% of taxable income in a given year, and limitations on the deduction for interest expense incurred in 2018 or later of up to 30% of its adjusted taxable income (defined as taxable income before interest and net operating losses) for the taxable year. For the tax years beginning before January 1, 2022, the adjusted taxable income for these purposes is also adjusted to exclude the impact of depreciation, depletion and amortization. The Tax Cuts and Jobs Act preserved deductibility of intangible drilling costs for federal income tax purposes, which allows the Company to deduct a portion of drilling costs in the year incurred and minimizes current taxes payable in periods of taxable income. At December 31, 2018, the Company has completed its accounting for the tax effects of enactment of the Tax Cuts and Jobs Act. The Company has remeasured certain deferred federal tax assets and liabilities based on the rates at which they are expected to reverse in the future, which is generally 21%. The amount recognized related to the remeasurement of its deferred federal tax balance was $140.4 million, which was subject to a valuation allowance. The Tax Cuts and Jobs Act repealed the AMT for tax years beginning on or after January 1, 2018 and provides that existing AMT credit carryforwards can be utilized to offset federal taxes for any taxable year. In addition, 50% of any unused AMT credit carryforwards can be refunded during tax years 2018 through 2020. The Company has $20.4 million of unused AMT credit carryforwards as of December 31, 2018.

The difference between the customary rate of 35% for 2016 and 2017 and 21% for 2018 and the effective tax rate on income (losses) is due to the following:

	Predecessor			Successor
	For the Years Ended December 31,		For the Period from January 1, 2018 through August 13, 2018	For the Period from August 14, 2018 through December 31, 2018
	2016	2017		
	(In thousands)			
Tax benefit at statutory rate	$ (44,788)	$ (45,272)	$ (19,255)	$ 17,444
Tax effect of:				
AMT credit refundable	—	(19,086)	—	(1,349)
Valuation allowance on deferred tax assets	69,890	41,116	22,053	(903)
State income taxes, net of federal benefit	(18,860)	(892)	(3,599)	3,863
Nondeductible stock-based compensation	73	1,408	668	(120)
Net operating loss expirations	—	1,548	—	—
Other	854	3,234	1,198	9
Total	$ 7,169	$ (17,944)	$ 1,065	$ 18,944

	Predecessor			Successor
	For the Years Ended December 31,		For the Period from January 1, 2018 through August 13, 2018	For the Period from August 14, 2018 through December 31, 2018
	2016	2017		
	(In thousands)			
Tax at statutory rate	35.0%	35.0%	21.0%	21.0%
Tax effect of:				
AMT credit refundable	—	14.8	—	(1.6)
Valuation allowance on deferred tax assets	(54.6)	(31.8)	(24.1)	(1.1)
State taxes, net of federal tax benefit	14.7	0.7	3.9	4.7
Nondeductible compensation	(0.1)	(1.1)	(0.7)	(0.1)
Net operating loss expirations	—	(1.2)	—	—
Other	(0.6)	(2.5)	(1.3)	—
Effective tax rate	(5.6%)	13.9%	(1.2)%	22.9%

The tax effects of significant temporary differences representing the net deferred tax liability at December 31, 2017 and 2018 were as follows:

	Predecessor	Successor
	2017	2018
	(In thousands)	
Deferred tax assets:		
Asset retirement obligation	$ 3,489	$ 2,329
Net operating loss carryforwards	289,803	65,317
Alternative minimum tax carryforward	1,349	—
Interest expense limitation	—	45,265
Gain on debt exchange and original issue discount	4,336	42
Other	3,782	3,711
	302,759	116,664
Valuation allowance on deferred tax assets	(298,539)	(18,390)
Deferred tax assets	4,220	98,274
Deferred tax liabilities:		
Property and equipment	(11,878)	(252,668)
Unrealized hedging income	(277)	(3,399)
Other	(2,331)	(4,124)
Deferred tax liabilities	(14,486)	(260,191)
Net deferred tax liability	$ (10,266)	$ (161,917)

At December 31, 2018, Comstock had the following carryforwards available to reduce future income taxes:

Types of Carryforward	Years of Expiration Carryforward	Amount (In thousands)
Net operating loss – U.S. federal	2019-2037	$ 930,835
Net operating loss – U.S. federal	Unlimited	$ 132,754
Net operating loss – state taxes	2020-2037	$ 1,531,788
Interest expense – U.S. Federal	Unlimited	$ 215,549

The shares of common stock issued as a result of the Jones Contribution triggered an ownership change under Section 382 of the Internal Revenue Code. As a result, the Company's ability to use net operating losses ("NOLs") generated before the change in control to reduce taxable income is generally limited to an annual amount based on the fair market value of its stock immediately prior to the ownership change multiplied by the long-term tax-exempt interest rate. The Company's NOLs are estimated to be limited to $3.3 million a year as a result of this limitation. In addition to this limitation, IRC Section 382 provides that a corporation with a net unrealized built-in gain immediately before an ownership change may increase its limitation by the amount of built-in gain recognized during a recognition period, which is generally the five-year period immediately following an ownership change. Based on the fair market value of the Company's common stock immediately prior to the ownership change, Comstock believes that it has a net unrealized built-in gain which will increase the Section 382 limitation during the five-year recognition period.

NOLs that exceed the Section 382 limitation in any year continue to be allowed as carry forwards until they expire and can be used to offset taxable income for years within the carryover period subject to the limitation in each year. NOLs incurred prior to 2018 generally have a 20-year life until they expire.

NOLs generated in 2018 and after would be carried forward indefinitely. Comstock's use of new NOLs arising after the date of an ownership change would not be affected by the 382 limitation. If the Company does not generate a sufficient level of taxable income prior to the expiration of the pre-2018 NOL carry-forward periods, then it will lose the ability to apply those NOLs as offsets to future taxable income. The Company estimates that $843.0 million of the U.S. federal NOL carryforwards and $1.3 billion of the estimated state NOL carryforwards will expire unused.

The Company's federal income tax returns for the years subsequent to December 31, 2014 remain subject to examination. The Company's income tax returns in major state income tax jurisdictions remain subject to examination for various periods subsequent to December 31, 2012. The Company currently believes that its significant filing positions are highly certain and that all of its other significant income tax filing positions and deductions would be sustained upon audit or the final resolution would not have a material effect on the consolidated financial statements. Therefore, the Company has not established any significant reserves for uncertain tax positions.

(10) Derivative Financial Instruments and Hedging Activities

Comstock periodically uses swaps, floors and collars to hedge oil and natural gas prices in order to manage oil and natural gas price risk. Swaps are settled monthly based on differences between the prices specified in the instruments and the settlement prices of futures contracts. Generally, when the applicable settlement price is less than the price specified in the contract, Comstock receives a settlement from the counterparty based on the difference multiplied by the volume or amounts hedged. Similarly, when the applicable settlement price exceeds the price specified in the contract, Comstock pays the counterparty based on the difference. Comstock generally receives a settlement from the counterparty for floors when the applicable settlement price is less than the price specified in the contract, which is based on the difference multiplied by the volumes hedged. For collars, generally Comstock receives a settlement from the counterparty when the settlement price is below the floor and pays a settlement to the counterparty when the settlement price exceeds the cap. No settlement occurs when the settlement price falls between the floor and cap.

All of the Company's derivative financial instruments are used for risk management purposes and by policy none are held for trading or speculative purposes. Comstock minimizes credit risk to counterparties of its derivative financial instruments through formal credit policies, monitoring procedures, and diversification. The Company is not required to provide any credit support to its counterparties other than cross collateralization with the assets securing its bank credit facility. None of the Company's derivative financial instruments involve payment or receipt of premiums. The Company classifies the fair value amounts of derivative financial instruments as net current or noncurrent assets or liabilities, whichever the case may be, by commodity and counterparty.

All of Comstock's natural gas derivative financial instruments are tied to the Henry Hub-NYMEX price index and all of its oil derivative financial instruments are tied to the WTI-NYMEX index price.

The Company had the following outstanding derivative financial instruments for natural gas price risk management at December 31, 2018:

	Future Production Period: Year Ended December 31, 2019
Natural Gas Swap contracts:	
Volume (MMbtu)	8,700,000
Average Price per MMbtu	$3.84
Natural Gas Collar contracts:	
Volume (MMbtu)	34,104,500
Price per MMbtu:	
Average Ceiling	$3.45
Average Floor	$2.44
Oil Collar contracts:	
Volume (Barrels)	1,163,100
Price per Barrel:	
Average Ceiling	$74.56
Average Floor	$52.35

Subsequent to December 31, 2018, the Company has added 18,150,000 MMBtu of additional natural gas collar agreements at an average contract ceiling price of $3.70 per MMBtu and an average contract floor price of $2.51 per MMBtu. These contracts begin in February 2019 and expire in March 2020. Since January 1, 2019 the Company has also added 426,000 barrels of additional oil collar agreements at an average contract ceiling price of $65.79 per barrel and an average contract floor price of $44.63 per barrel. These contracts begin in February 2019 and expire in March 2020. None of the derivative contracts were designated as cash flow hedges. The Company recognizes cash settlements and changes in the fair value of its derivative financial instruments as a single component of other income (expenses).

None of the Company's derivative contracts were designated as cash flow hedges. The aggregate fair value of the Company's derivative instruments reported in the accompanying consolidated balance sheets by type, including the classification between assets and liabilities, consists of the following:

Type	Consolidated Balance Sheet Location	Fair Value	Gross Amounts Offset in the Consolidated Balance Sheet	Net Fair Value Presented in the Consolidated Balance Sheet
			(in thousands)	
Predecessor Fair Value of Derivative Instruments as of December 31, 2017				
Asset Derivatives:				
Natural gas price derivatives	Derivative Financial Instruments – current	$ $1,318	$ —	$ 1,318
Successor Fair Value of Derivative Instruments as of December 31, 2018				
Asset Derivatives:				
Natural gas price derivatives	Derivative Financial Instruments – current	$ 7,264	$ (1,168)	$ 6,096
Oil price derivatives	Derivative Financial Instruments – current	$ 9,305	$ —	$ 9,305
Liability Derivatives:				
Natural gas price derivatives	Derivative Financial Instruments – current	$ 1,168	$ (1,168)	$ —
				$ 15,401

The Company recognized cash settlements and changes in the fair value of its derivative financial instruments as a single component of other income (expenses). Gains and losses related to the change in the fair value of the Company's derivative contracts recognized in the consolidated statement of operations were as follows:

Location of Gain/(Loss) Recognized in Earnings on Derivatives	Predecessor: Years Ended December 31, 2016	Predecessor: Years Ended December 31, 2017	Predecessor: For the Period from January 1, 2018 through August 13, 2018	Successor: For the Period from August 14, 2018 through December 31, 2018
	(In thousands)			
Gain (loss) from derivative financial instruments	$ (5,356)	$ 16,753	$ 881	$ 10,465

(11) Supplementary Quarterly Financial Data (Unaudited)

	2017 First	2017 Second	2017 Third	2017 Fourth
	(In thousands, except per share data)			
Total oil and gas sales	$ 53,801	$ 61,471	$ 66,811	$ 73,248
Operating loss	$ 2,381	$ 10,470	$ 11,190	$ (24,224)
Net income (loss)	$ (22,931)	$ (21,442)	$ (24,736)	$ (42,296)
Income (loss) per share:				
Basic and diluted	$ (1.61)	$ (1.45)	$ (1.67)	$ (2.86)

	2018 Predecessor: First	Predecessor: Second	Predecessor: July 1 through August 13	Successor: August 14 through September 30	Successor: Fourth
	(In thousands, except per share data)				
Total oil and gas sales	$ 72,593	$ 61,449	$ 32,588	$ 70,123	$ 153,498
Operating income (loss)	$ (5,122)	$ 7,716	$ 8,228	$ 34,581	$ 81,450
Net loss	$ (41,886)	$ (34,003)	$ (16,865)	$ 13,823	$ 50,299
Income (loss) per share:					
Basic and diluted	$ (2.78)	$ (2.23)	$ (1.09)	$ 0.13	$ 0.48

Basic and diluted per share amounts are the same for each of the quarters where a net loss was reported.

Results of operations include the following non-routine items of income (expense), which are presented before the effect of income taxes:

	2017 First	2017 Second	2017 Third	2017 Fourth
	(In thousands)			
Gain (loss) on sale of oil and gas properties	$ (24)	$ —	$ (1,036)	$ —
Impairments of proved oil and gas properties	$ —	$ —	$ —	$ (43,990)

	2018				
	Predecessor			Successor	
	First	Second	July 1 through August 13	August 14 through September 30	Fourth
	(In thousands)				
Gain (loss) on sale of oil and gas properties	$ (28,600)	$ (6,838)	—	$ 98	$ 57

(12) Oil and Gas Reserves Information (Unaudited)

Set forth below is a summary of the changes in Comstock's net quantities of oil and natural gas reserves:

	Predecessor						Successor	
	Years Ended December 31,				For the Period from January 1, 2018 through August 13, 2018		For the Period from August 14, 2018 through December 31, 201	
	2016		2017					
	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
Proved Reserves:								
Beginning of period	9,229	569,596	7,277	872,468	7,552	1,116,956	28,994 [1]	2,246,5
Revisions of previous estimates	(406)	130,416	1,232	33,721	4	17,778	5	23,9
Extensions and discoveries	64	285,076	1	291,881	5,651	950,032	—	30,1
Acquisitions of minerals in place	—	—	—	—	—	220,088	—	33,6
Sales of minerals in place	(222)	(58,942)	(7)	(7,593)	(6,870)	(54,341)	(4,002)	(6,3
Production	(1,388)	(53,678)	(951)	(73,521)	(287)	(55,240)	(1,385)	(45,0
End of period	7,277	872,468	7,552	1,116,956	6,050	2,195,273	23,612	2,282,7
Proved Developed Reserves:								
Beginning of period	9,229	311,130	7,277	321,527	7,552	436,114	22,845 [1]	550,1
End of period	7,277	321,527	7,552	436,114	403	500,031	21,466	583,1
Proved Undeveloped Reserves:								
Beginning of period	—	258,466	—	550,941	—	680,842	6,149 [1]	1,696,3
End of period	—	550,941	—	680,842	5,647	1,695,242	2,146	1,699,6
Reserves associated with Assets Held for Sale:								
Proved Reserves								
Beginning of period	8,701	9,119	6,950	9,915	7,116	10,484		
End of period	6,950	9,915	7,116	10,484	—	—		
Proved Developed Reserves								
Beginning of period	8,701	9,119	6,950	9,915	7,116	10,484		
End of period	6,950	9,915	7,116	10,484	—	—		
Proved Undeveloped Reserves								
Beginning of period	—	—	—	—	—	—		
End of period	—	—	—	—	—	—		

(1) The beginning proved reserves balance represents the contributed Bakken shale properties and the reserves of the Predecessor on a combined basis.

The significant upward revisions to previous estimates in Predecessor Year 2016 were primarily performance-related and were attributable to the Company's well performance in the Haynesville shale as well as the expansion of the Company's future drilling plans.

The following table sets forth the standardized measure of discounted future net cash flows relating to proved reserves :

	Predecessor				Successor	
	As of December 31, 2017		As of August 13, 2018		As of December 31, 2018	
			(In thousands)			
Cash Flows Relating to Proved Reserves:						
Future Cash Flows	$	3,588,764	$	6,384,203	$	8,054,092
Future Costs:						
Production		(986,398)		(1,804,559)		(2,160,912)
Development and Abandonment		(672,559)		(1,945,141)		(1,800,335)
Future Income Taxes		5,239		(199,589)		(622,241)
Future Net Cash Flows		1,935,046		2,434,914		3,470,604
10% Discount Factor		(1,053,502)		(1,556,927)		(1,996,764)
Standardized Measure of Discounted Future Net Cash Flows	$	881,544	$	877,987	$	1,473,840
Standardized Measure of Discounted Future Net Cash Flows Related to Assets Held for Sale	$	109,134	$	—	$	—

The following table sets forth the changes in the standardized measure of discounted future net cash flows relating to proved reserves:

	Predecessor						Successor	
	Years Ended December 31,				For the Period from January 1, 2018 through August 13, 2018		For the Period from August 14, 2018 through December 31, 2018	
	2016		2017					
			(In thousands)					
Standardized Measure, Beginning of Year	$	372,139	$	429,275	$	881,544	$	1,317,383 [1]
Net change in sales price, net of production costs		(45,379)		326,662		(61,662)		223,731
Development costs incurred during the year which were previously estimated		45,648		119,864		86,086		112,073
Revisions of quantity estimates		113,583		57,042		19,815		27,090
Accretion of discount		37,251		43,130		53,413		55,692
Changes in future development and abandonment costs		5,315		(62,509)		(27,489)		23,139
Changes in timing and other		(38,071)		(15,565)		(17,723)		9,434
Extensions and discoveries		70,149		167,135		167,986		15,263
Acquisitions of minerals in place		—		—		72,738		54,143
Sales of minerals in place		(22,449)		(6,027)		(124,083)		(42,870)
Sales, net of production costs		(107,253)		(194,562)		(129,991)		(181,218)
Net changes in income taxes		(1,658)		17,099		(42,647)		(140,020)
Standardized Measure, End of Year	$	429,275	$	881,544	$	877,987	$	1,473,840

(1) The beginning Standardized Measure represents the contributed Bakken shale properties and the reserves of the Predecessor on a combined basis.

The standardized measure of discounted future net cash flows was determined based on the simple average of the first of month market prices for oil and natural gas for each year. Prices used in determining quantities of oil and natural gas reserves and future cash inflows from oil and natural gas reserves represent prices received at the Company's sales point. These prices have been adjusted from posted or index prices for both location and quality differences.

Prices used in determining oil and natural gas reserves quantities and cash flows are as follows:

	Predecessor			Successor
	Years Ended December 31,		For the Period from January 1, 2018 through August 13, 2018	For the Period from August 14, 2018 through December 31, 2018
	2016	2017		
Crude Oil: $/ barrel	$ 37.62	$ 48.71	$ 62.29	$ 61.21
Natural Gas: $/Mcf	$ 2.29	$ 2.88	$ 2.74	$ 2.90

The proved oil and gas reserves utilized in the preparation of the financial statements were estimated by Lee Keeling and Associates, independent petroleum consultants, in accordance with guidelines established by the Securities and Exchange Commission and the Financial Accounting Standards Board, which require that reserve reports be prepared under existing economic and operating conditions with no provision for price and cost escalation except by contractual agreement. All of the Company's reserves are located onshore in the continental United States of America.

Future development and production costs are computed by estimating the expenditures to be incurred in developing and producing proved oil and gas reserves at the end of the year, based on year end costs and assuming continuation of existing economic conditions. Future income tax expenses are computed by applying the appropriate statutory tax rates to the future pre-tax net cash flows relating to proved reserves, net of the tax basis of the properties involved. The future income tax expenses give effect to permanent differences and tax credits, but do not reflect the impact of future operations.

Exhibit 21

SUBSIDIARIES OF COMSTOCK RESOURCES, INC.

Name	Incorporation	Business Name
Comstock Oil & Gas GP, LLC	Nevada	Comstock Oil & Gas GP, LLC
Comstock Oil & Gas Investments, LLC	Nevada	Comstock Oil & Gas Investments, LLC
Comstock Oil & Gas, LP(1)	Nevada	Comstock Oil & Gas, LP
Comstock Oil & Gas Holdings, Inc.(2)	Nevada	Comstock Oil & Gas Holdings, Inc.
Comstock Oil & Gas – Louisiana, LLC(3)	Nevada	Comstock Oil & Gas – Louisiana, LLC

(1) Comstock Oil & Gas GP, LLC is the general partner and Comstock Oil & Gas Investments, LLC is the limited partner of this partnership
(2) 100% owned by Comstock Oil & Gas, LP
(3) 100% owned by Comstock Oil & Gas Holdings, Inc.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

(1) Registration Statement (Form S-3 No. 333-217453) of Comstock Resources, Inc.,
(2) Registration Statement (Form S-8 No. 333-214945) pertaining to the Comstock Resources, Inc. 2009 Long-Term Incentive Plan,
(3) Registration Statement (Form S-8 No. 033-88962) pertaining to the Comstock Resources, Inc. 401(k) Profit Sharing Plan,
(4) Registration Statement (Form S-8 No. 333-207180) pertaining to the Comstock Resources, Inc. 2009 Long-Term Incentive Plan, and
(5) Registration Statement (Form S-8 No. 333-159332) pertaining to the Comstock Resources, Inc. 2009 Long-Term Incentive Plan, and
(6) Registration Statement (Form S-3 No. 333-228311) of Comstock Resources, Inc. shares;

of our reports dated March 1, 2019, with respect to the consolidated financial statements of Comstock Resources, Inc. and subsidiaries and the effectiveness of internal control over financial reporting of Comstock Resources, Inc. and subsidiaries included in this Annual Report (Form 10-K) for the year ended December 31, 2018.

/s/ ERNST & YOUNG LLP

Dallas, Texas
March 1, 2019

Exhibit 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

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

(1) Registration Statement (Form S-3 No. 333-217453) of Comstock Resources, Inc.,
(2) Registration Statement (Form S-8 No. 333-214945) pertaining to the Comstock Resources, Inc. 2009 Long-Term Incentive Plan,
(3) Registration Statement (Form S-8 No. 033-88962) pertaining to the Comstock Resources, Inc. 401(k) Profit Sharing Plan,
(4) Registration Statement (Form S-8 No. 333-207180) pertaining to the Comstock Resources, Inc. 2009 Long-Term Incentive Plan, and
(5) Registration Statement (Form S-8 No. 333-159332) pertaining to the Comstock Resources, Inc. 2009 Long-Term Incentive Plan, and
(6) Registration Statement (Form S-3 No. 333-228311) of Comstock Resources, Inc. shares;

of the reference of our firm and to the reserve estimates as of December 31, 2018 and our report thereon in the Annual Report on Form 10-K for the year ended December 31, 2018 of Comstock Resources, Inc. and subsidiaries, filed with the Securities and Exchange Commission.

/s/ LEE KEELING AND ASSOCIATES, INC.

Tulsa, Oklahoma
March 1, 2019

Exhibit 31.1

Section 302 Certification

I, M. Jay Allison, certify that:

1. I have reviewed this Annual Report on Form 10-K of Comstock Resources, Inc;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the 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: March 1, 2019

/s/ M. JAY ALLISON
Chief Executive Officer

Exhibit 31.2

Section 302 Certification

I, Roland O. Burns, certify that:

1. I have reviewed this Annual Report on Form 10-K of Comstock Resources, Inc;

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

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

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

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

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

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

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

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the 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: March 1, 2019

/s/ ROLAND O. BURNS
President and Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Comstock Resources, Inc. (the “Company”) on Form 10-K for the year ending December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, M. Jay Allison, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) 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 result of operations of the Company.

/s/ M. JAY ALLISON

M. Jay Allison
Chief Executive Officer
March 1, 2019

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Comstock Resources, Inc. (the "Company") on Form 10-K for the year ending December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Roland O. Burns, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) 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 result of operations of the Company.

/s/ ROLAND O. BURNS
Roland O. Burns
Chief Financial Officer
March 1, 2019

LEE KEELING AND ASSOCIATES, INC.

INTERNATIONAL PETROLEUM CONSULTANTS

115 West 3rd Street, Suite 700
Tulsa, Oklahoma 74103-3410
(918) 587-5521
www.lkaengineers.com

January 24, 2019

Comstock Resources, Inc.
5300 Town and Country Boulevard, Ste. 500
Frisco, Texas 75034

Attention: Mr. M. Jay Allison
C.E.O.

RE: Estimated Reserves and
Future Net Revenue
Comstock Resources, Inc.
Constant Prices and & Non-Escalated Expenses

Gentlemen:

In accordance with your request, we have prepared an estimate of net reserves and future net revenue to be realized from the interests owned by Comstock Resources, Inc. (Comstock) for 2018 year-end SEC reporting. These interests are in oil and gas properties located in the states of Louisiana, Mississippi, Montana, New Mexico, North Dakota, Oklahoma, Texas, and Wyoming. Reserves estimated by us reflect 100% of Comstock's corporate proved reserves. In addition to being in compliance with requirements established by the Society of Petroleum Engineers (SPE), American Association of Petroleum Geologists (AAPG), World Petroleum Congress (WPC) and the Society of Petroleum Evaluation Engineers (SPEE) this report also complies with the Securities and Exchange Commission (SEC) guidelines as published in the Federal Register January 14, 2009. The effective date of this estimate is December 31, 2018. It was completed January 24, 2019, and the results are summarized as follows:

	ESTIMATED REMAINING NET RESERVES		NET GAS* EQUIVALENT	FUTURE NET REVENUE	
RESERVE CLASSIFICATION	Oil (BBLS)	Gas (MCF)	(MCFE)	Total ($)	Present Worth Disc.@10% ($)
Proved Developed					
Producing	20,938,782	543,741,184	669,373,824	1,975,042,688	1,127,448,960
Non-Producing	476,430	23,617,986	26,476,568	60,452,740	35,941,556
Behind-Pipe	50,706	15,747,611	16,051,845	27,806,042	12,494,657
Sub-Total	21,465,918	583,106,781	711,902,237	2,063,301,470	1,175,885,173
Proved Undeveloped	2,146,204	1,699,651,456	1,712,528,640	2,012,582,656	579,259,008
Total All Reserves	23,612,122	2,282,758,237	2,424,430,877	4,075,884,126	1,755,144,181

* Net Gas Equivalent is calculated based on a conversion factor of 6 MCF of gas per barrel of oil.
Note: Totals may not agree with schedules due to computer roundoff.

Future net revenue is the amount, exclusive of state and federal income taxes, which will accrue to Comstock's interest from continued operation of the properties to depletion. It should not be construed as a fair market or trading value.

No attempt has been made to quantify or otherwise account for any accumulative gas production imbalances that may exist. Neither has an attempt been made to determine whether the wells and facilities are in compliance with various governmental regulations, nor have costs been included in the event they are not.

This report consists of various summaries. Schedule No. 1 presents summary forecasts of annual gross and net production, severance and ad valorem taxes, operating income, and net revenue by reserve type. Schedule No. 2 is a sequential listing of the individual properties based on discounted future net revenue. Schedule No. 3 is a sequential listing of the individual properties based on discounted future net revenue by reserve category. An alphabetical one-line summary by property is presented on Schedule No. 4. A one-line listing of the individual properties, ordered by reserve category, state and project, is presented on Schedule No. 5. A geographical one-line summary by state, project and lease is shown on Schedule No. 6.

<u>CLASSIFICATION OF RESERVES</u>

Reserves assigned to the various leases and/or wells have been classified as either "proved developed" or "proved undeveloped" in accordance with the definitions of the proved reserves as promulgated by the Securities and Exchange Commission (SEC). See the attached Appendix: SEC Petroleum Reserve Definitions.

<u>Developed Producing (Petroleum Resources Management System (PRMS) Definitions</u>

Although not required for disclosure under SEC regulations, Proved Oil and Gas Reserves may be further sub-classified as Producing or Non-Producing according to PRMS definitions set out below:

- Developed Producing (PDP) Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.
- Developed Non-Producing (PDNP) Reserves include shut-in and behind-pipe reserves.
  - Shut-In Reserves are expected to be recovered from:
    1. Completion intervals which are open at the time of the estimate but which have not yet started producing.
    2. Wells which were shut-in for market conditions or pipeline connections; or
    3. Wells not capable of production for mechanical reasons.
  - Behind-Pipe Reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion prior to start of production.

  In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

<u>ESTIMATION OF RESERVES</u>

The majority of the subject wells have been producing for a considerable length of time. Reserves attributable to wells with a well-defined production and/or pressure decline trend were based upon extrapolation of that trend to an economic limit and/or abandonment pressure.

Reserves anticipated from new wells were based upon volumetric calculations or analogy with similar properties, which are producing from the same horizons in the respective areas. Structural position, net pay thickness, well productivity, gas/oil ratios, water production, pressures, and other pertinent factors were considered in the estimation of these reserves.

Reserves assigned to behind-pipe zones and undeveloped locations have been estimated based on volumetric calculations and/or analogy with other wells in the area producing from the same horizon.

FUTURE NET REVENUE

Oil Income and Prices

Income from the sale of oil was estimated based on the unweighted average price for NYMEX West Texas Intermediate for the first day of each month for January through December of 2018, as provided by the staff of Comstock. The computed reference price of $65.56 per barrel was held constant throughout the life of each lease. The reference price was adjusted for historical differentials between posted prices and actual field prices to reflect quality, transportation fees and regional price differences. Provisions were made for state severance and ad valorem taxes where applicable.

Gas Income and Prices

Income from the sale of gas was estimated based on the average price for natural gas sold at Henry Hub the first day of each month for January through December of 2018, as provided by staff of Comstock. The computed reference price of $3.10 per MCF was held constant throughout the life of each lease. The reference price was adjusted for basis differentials, marketing, and transportation costs. Provisions were made for state severance and ad valorem taxes where applicable.

Operating Expenses

Operating expenses were based upon actual operating costs charged by the respective operators as supplied by the staff of Comstock or were based upon the actual experience of the operators in the respective areas. For leases operated by Comstock, monthly operating costs included lease operating expenses and overhead charges. All expenses reflect known operational conditions throughout the life of each lease.

Future Expenses and Abandonment Costs

As provided by Comstock, provisions have been made for future expenses required for drilling, recompletion and/or abandonment costs. These costs have been held constant from current estimates.

QUALIFICATIONS OF LEE KEELING AND ASSOCIATES, INC.

Lee Keeling and Associates, Inc. has been offering consulting engineering and geological services to integrated oil companies, independent operators, investors, financial institutions, legal firms, accounting firms and governmental agencies since 1957. Its professional staff is experienced in all productive areas of the United States, Canada, Latin America and many other foreign countries. The firm's reports are recognized by major financial institutions and used as the basis for oil company mergers, purchases, sales, financing of projects and for registration purposes with financial and regulatory authorities throughout the world.

GENERAL

Information upon which this estimate of net reserves and future net revenue has been based was furnished by the staff of Comstock or was obtained by us from outside sources we consider to be reliable. This information is assumed to be correct. No attempt has been made to verify title or ownership of the subject properties. Interests attributed to wells to be drilled at undeveloped locations are based on current ownership. Leases were not inspected by a representative of this firm, nor were the wells tested under our supervision; however, the performance of the majority of the wells was discussed with employees of Comstock.

This report has been prepared utilizing all methods and procedures regularly used by petroleum engineers to estimate oil and gas reserves for properties of this type and character, and we have used all methods and procedures necessary to prepare this report. The recovery of oil and gas reserves and projection of producing rates are dependent upon many variable factors including prudent operation, compression of gas when needed, market demand, installation of lifting equipment, and remedial work when required. The reserves included in this report have been based upon the assumption that the wells will be operated in a prudent manner under the same conditions existing on the effective date. Actual production results and future well data may yield additional facts, not presently available to us, which may require an adjustment to our estimates. The assumptions, data, methods and procedures used in connection with the preparation of this report are appropriate for the purpose served by this report.

The reserves included in this report are estimates only and should not be construed as being exact quantities. They may or may not be actually recovered and if recovered, the revenues therefrom and the actual costs related thereto could be more or less than the estimated amounts. As in all aspects of oil and gas estimation, there are uncertainties inherent in the interpretation of engineering data and, therefore, our conclusions necessarily represent only informed professional judgments.

The projection of cash flow has been made assuming constant prices. There is no assurance that prices will not vary. For this reason and those listed in the previous paragraph, the future net cash from the sale of production from the subject properties may vary from the estimates contained in this report.

It should be pointed out that regulatory authorities could, in the future, change the allocation of reserves allowed to be produced from a particular well in any reservoir, thereby altering the material premise upon which our reserve estimates may be based.

The information developed during the course of this investigation, basic data, maps and worksheets showing recovery determinations are available for inspection in our office.

We appreciate this opportunity to be of service to you.

Very truly yours,

/S/LEE KEELING AND ASSOCIATES, INC
LEE KEELING AND ASSOCIATES, INC.

Appendix
SEC Petroleum Reserve Definitions

§210.4-10 Financial accounting and reporting for oil and gas producing activities pursuant to the Federal securities laws and the Energy Policy and Conservation Act of 1975.

This section prescribes financial accounting and reporting standards for registrants with the Commission engaged in oil and gas producing activities in filings under the Federal securities laws and for the preparation of accounts by persons engaged, in whole or in part, in the production of crude oil or natural gas in the United States, pursuant to section 503 of the Energy Policy and Conservation Act of 1975 (42 U.S.C. 6383) (*EPCA*) and section 11(c) of the Energy Supply and Environmental Coordination Act of 1974 (15 U.S.C. 796) (*ESECA*), as amended by section 505 of EPCA. The application of this section to those oil and gas producing operations of companies regulated for ratemaking purposes on an individual-company-cost-of-service basis may, however, give appropriate recognition to differences arising because of the effect of the ratemaking process.

Exemption. Any person exempted by the Department of Energy from any record-keeping or reporting requirements pursuant to section 11(c) of ESECA, as amended, is similarly exempted from the related provisions of this section in the preparation of accounts pursuant to EPCA. This exemption does not affect the applicability of this section to filings pursuant to the Federal securities laws.

DEFINITIONS

(a) *Definitions.* The following definitions apply to the terms listed below as they are used in this section:

(1) ***Acquisition of properties***. Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) ***Analogous reservoir.*** Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an “analogous reservoir” refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);

(ii) Same environment of deposition;

(iii) Similar geological structure; and

(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) ***Bitumen***. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) ***Condensate***. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) ***Deterministic estimate.*** The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) ***Developed oil and gas reserves***. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

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

(7) ***Development costs.*** Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.

(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.

(iv) Provide improved recovery systems.

(8) ***Development project***. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) ***Development well***. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) ***Economically producible***. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) ***Estimated ultimate recovery (EUR)***. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) ***Exploration costs***. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or *G&G* costs.

(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.

(iii) Dry hole contributions and bottom hole contributions.

(iv) Costs of drilling and equipping exploratory wells.

(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) ***Exploratory well***. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) ***Extension well.*** An extension well is a well drilled to extend the limits of a known reservoir.

(15) ***Field***. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious, strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms *structural feature* and *stratigraphic condition* are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) ***Oil and gas producing activities***. (i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;

(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;

(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:

(*1*) Lifting the oil and gas to the surface; and

(*2*) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and

b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;

(B) Processing of produced oil, gas or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;

(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or

(D) Production of geothermal steam.

(17) ***Possible reserves.*** Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) ***Probable reserves***. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) ***Probabilistic estimate***. The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) ***Production costs***. (i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.

(B) Repairs and maintenance.

(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.

(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) ***Proved area.*** The part of a property to which proved reserves have been specifically attributed.

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

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

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

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

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

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

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

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

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

(23) ***Proved properties***. Properties with proved reserves.

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

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

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

NOTE TO PARAGRAPH (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (*i.e.*, absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (*i.e.*, potentially recoverable resources from undiscovered accumulations).

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

(28) ***Resources***. Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) ***Service well***. A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) ***Stratigraphic test well.*** A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) ***Undeveloped oil and gas reserves.*** Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

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

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) ***Unproved properties.*** Properties with no proved reserves.

SUCCESSFUL EFFORTS METHOD

(b) A reporting entity that follows the successful efforts method shall comply with the accounting and financial reporting disclosure requirements of FASB ASC Topic 932, *Extractive Activities—Oil and Gas.*

FULL COST METHOD

(c) *Application of the full cost method of accounting.* A reporting entity that follows the full cost method shall apply that method to all of its operations and to the operations of its subsidiaries, as follows:

(1) *Determination of cost centers.* Cost centers shall be established on a country-by-country basis.

(2) *Costs to be capitalized.* All costs associated with property acquisition, exploration, and development activities (as defined in paragraph (a) of this section) shall be capitalized within the appropriate cost center. Any internal costs that are capitalized shall be limited to those costs that can be directly identified with acquisition, exploration, and development activities undertaken by the reporting entity for its own account, and shall not include any costs related to production, general corporate overhead, or similar activities.

(3) *Amortization of capitalized costs.* Capitalized costs within a cost center shall be amortized on the unit-of-production basis using proved oil and gas reserves, as follows:

(i) Costs to be amortized shall include (A) all capitalized costs, less accumulated amortization, other than the cost of properties described in paragraph (ii) below; (B) the estimated future expenditures (based on current costs) to be incurred in developing proved reserves; and (C) estimated dismantlement and abandonment costs, net of estimated salvage values.

(ii) The cost of investments in unproved properties and major development projects may be excluded from capitalized costs to be amortized, subject to the following:

(A) All costs directly associated with the acquisition and evaluation of unproved properties may be excluded from the amortization computation until it is determined whether or not proved reserves can be assigned to the properties, subject to the following conditions:

(*1*) Until such a determination is made, the properties shall be assessed at least annually to ascertain whether impairment has occurred. Unevaluated properties whose costs are individually significant shall be assessed individually. Where it is not practicable to individually assess the amount of impairment of properties for which costs are not individually significant, such properties may be grouped for purposes of assessing impairment. Impairment may be estimated by applying factors based on historical experience and other data such as primary lease terms of the properties, average holding periods of unproved properties, and geographic and geologic data to groupings of individually insignificant properties and projects. The amount of impairment assessed under either of these methods shall be added to the costs to be amortized.

(*2*) The costs of drilling exploratory dry holes shall be included in the amortization base immediately upon determination that the well is dry.

(*3*) If geological and geophysical costs cannot be directly associated with specific unevaluated properties, they shall be included in the amortization base as incurred. Upon complete evaluation of a property, the total remaining excluded cost (net of any impairment) shall be included in the full cost amortization base.

(B) Certain costs may be excluded from amortization when incurred in connection with major development projects expected to entail significant costs to ascertain the quantities of proved reserves attributable to the properties under development (e.g., the installation of an offshore drilling platform from which development wells are to be drilled, the installation of improved recovery programs, and similar major projects undertaken in the expectation of significant additions to proved reserves). The amounts which may be excluded are applicable portions of (*1*) the costs that relate to the major development project and have not previously been included in the amortization base, and (*2*) the estimated future expenditures associated with the development project. The excluded portion of any common costs associated with the development project should be based, as is most appropriate in the circumstances, on a comparison of either (*i*) existing proved reserves to total proved reserves expected to be established upon completion of the project, or (*ii*) the number of wells to which proved reserves have been assigned and total number of wells expected to be drilled. Such costs may be excluded from costs to be amortized until the earlier determination of whether additional reserves are proved or impairment occurs.

(C) Excluded costs and the proved reserves related to such costs shall be transferred into the amortization base on an ongoing (well-by-well or property-by-property) basis as the project is evaluated and proved reserves established or impairment determined. Once proved reserves are established, there is no further justification for continued exclusion from the full cost amortization base even if other factors prevent immediate production or marketing.

(iii) Amortization shall be computed on the basis of physical units, with oil and gas converted to a common unit of measure on the basis of their approximate relative energy content, unless economic circumstances (related to the effects of regulated prices) indicate that use of units of revenue is a more appropriate basis of computing amortization. In the latter case, amortization shall be computed on the basis of current gross revenues (excluding royalty payments and net profits disbursements) from production in relation to future gross revenues, based on current prices (including consideration of changes in existing prices provided only by contractual arrangements), from estimated production of proved oil and gas reserves. The effect of a significant price increase during the year on estimated future gross revenues shall be reflected in the amortization provision only for the period after the price increase occurs.

(iv) In some cases it may be more appropriate to depreciate natural gas cycling and processing plants by a method other than the unit-of-production method.

(v) Amortization computations shall be made on a consolidated basis, including investees accounted for on a proportionate consolidation basis. Investees accounted for on the equity method shall be treated separately.

(4) *Limitation on capitalized costs.* (i) For each cost center, capitalized costs, less accumulated amortization and related deferred income taxes, shall not exceed an amount (the cost center ceiling) equal to the sum of:

(A) The present value of estimated future net revenues computed by applying current prices of oil and gas reserves (with consideration of price changes only to the extent provided by contractual arrangements) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet presented, less estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves computed using a discount factor of ten percent and assuming continuation of existing economic conditions; plus

(B) the cost of properties not being amortized pursuant to paragraph (i)(3)(ii) of this section; plus

(C) the lower of cost or estimated fair value of unproven properties included in the costs being amortized; less

(D) income tax effects related to differences between the book and tax basis of the properties referred to in paragraphs (i)(4)(i) (B) and (C) of this section.

(ii) If unamortized costs capitalized within a cost center, less related deferred income taxes, exceed the cost center ceiling, the excess shall be charged to expense and separately disclosed during the period in which the excess occurs. Amounts thus required to be written off shall not be reinstated for any subsequent increase in the cost center ceiling.

(5) *Production costs.* All costs relating to production activities, including workover costs incurred solely to maintain or increase levels of production from an existing completion interval, shall be charged to expense as incurred.

(6) *Other transactions.* The provisions of paragraph (h) of this section, “Mineral property conveyances and related transactions if the successful efforts method of accounting is followed,” shall apply also to those reporting entities following the full cost method except as follows:

(i) *Sales and abandonments of oil and gas properties.* Sales of oil and gas properties, whether or not being amortized currently, shall be accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center. For instance, a significant alteration would not ordinarily be expected to occur for sales involving less than 25 percent of the reserve quantities of a given cost center. If gain or loss is recognized on such a sale, total capitalization costs within the cost center shall be allocated between the reserves sold and reserves retained on the same basis used to compute amortization, unless there are substantial economic differences between the properties sold and those retained, in which case capitalized costs shall be allocated on the basis of the relative fair values of the properties. Abandonments of oil and gas properties shall be accounted for as adjustments of capitalized costs; that is, the cost of abandoned properties shall be charged to the full cost center and amortized (subject to the limitation on capitalized costs in paragraph (b) of this section).

(ii) *Purchases of reserves.* Purchases of oil and gas reserves in place ordinarily shall be accounted for as additional capitalized costs within the applicable cost center; however, significant purchases of production payments or properties with lives substantially shorter than the composite productive life of the cost center shall be accounted for separately.

(iii) *Partnerships, joint ventures and drilling arrangements.* (A) Except as provided in paragraph (i)(6)(i) of this section, all consideration received from sales or transfers of properties in connection with partnerships, joint venture operations, or various other forms of drilling arrangements involving oil and gas exploration and development activities (e.g., carried interest, turnkey wells, management fees, etc.) shall be credited to the full cost account, except to the extent of amounts that represent reimbursement of organization, offering, general and administrative expenses, etc., that are identifiable with the transaction, if such amounts are currently incurred and charged to expense.

(B) Where a registrant organizes and manages a limited partnership involved only in the purchase of proved developed properties and subsequent distribution of income from such properties, management fee income may be recognized provided the properties involved do not require aggregate development expenditures in connection with production of existing proved reserves in excess of 10% of the partnership's recorded cost of such properties. Any income not recognized as a result of this limitation would be credited to the full cost account and recognized through a lower amortization provision as reserves are produced.

(iv) *Other services.* No income shall be recognized in connection with contractual services performed (e.g. drilling, well service, or equipment supply services, etc.) in connection with properties in which the registrant or an affiliate (as defined in §210.1-02(b)) holds an ownership or other economic interest, except as follows:

(A) Where the registrant acquires an interest in the properties in connection with the service contract, income may be recognized to the extent the cash consideration received exceeds the related contract costs plus the registrant's share of costs incurred and estimated to be incurred in connection with the properties. Ownership interests acquired within one year of the date of such a contract are considered to be acquired in connection with the service for purposes of applying this rule. The amount of any guarantees or similar arrangements undertaken as part of this contract should be considered as part of the costs related to the properties for purposes of applying this rule.

(B) Where the registrant acquired an interest in the properties at least one year before the date of the service contract through transactions unrelated to the service contract, and that interest is unaffected by the service contract, income from such contract may be recognized subject to the general provisions for elimination of inter-company profit under generally accepted accounting principles.

(C) Notwithstanding the provisions of paragraphs (i)(6)(iv) (A) and (B) of this section, no income may be recognized for contractual services performed on behalf of investors in oil and gas producing activities managed by the registrant or an affiliate. Furthermore, no income may be recognized for contractual services to the extent that the consideration received for such services represents an interest in the underlying property.

(D) Any income not recognized as a result of these rules would be credited to the full cost account and recognized through a lower amortization provision as reserves are produced.

(7) *Disclosures.* Reporting entities that follow the full cost method of accounting shall disclose all of the information required by paragraph (k) of this section, with each cost center considered as a separate geographic area, except that reasonable groupings may be made of cost centers that are not significant in the aggregate. In addition:

(i) For each cost center for each year that an income statement is required, disclose the total amount of amortization expense (per equivalent physical unit of production if amortization is computed on the basis of physical units or per dollar of gross revenue from production if amortization is computed on the basis of gross revenue).

(ii) State separately on the face of the balance sheet the aggregate of the capitalized costs of unproved properties and major development projects that are excluded, in accordance with paragraph (i)(3) of this section, from the capitalized costs being amortized. Provide a description in the notes to the financial statements of the current status of the significant properties or projects involved, including the anticipated timing of the inclusion of the costs in the amortization computation. Present a table that shows, by category of cost, (A) the total costs excluded as of the most recent fiscal year; and (B) the amounts of such excluded costs, incurred (*1*) in each of the three most recent fiscal years and (*2*) in the aggregate for any earlier fiscal years in which the costs were incurred. Categories of cost to be disclosed include acquisition costs, exploration costs, development costs in the case of significant development projects and capitalized interest.

(8) For purposes of this paragraph (c), the term “current price” shall mean the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

INCOME TAXES

(d) *Income taxes.* Comprehensive interperiod income tax allocation by a method which complies with generally accepted accounting principles shall be followed for intangible drilling and development costs and other costs incurred that enter into the determination of taxable income and pretax accounting income in different periods.