Approach Resources Inc
Form 10-K
March 09, 2018

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, 2017

or

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

Commission file number: 001-33801

APPROACH RESOURCES INC.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	51-0424817 (I.R.S. Employer Identification Number)
One Ridgmar Centre 6500 West Freeway, Suite 800 Fort Worth, Texas (Address of principal executive offices)	76116 (Zip Code)

Registrant's telephone number, including area code

(817) 989-9000

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

Title of each class	Name of each exchange on which registered
Common stock, par value $0.01 per share	NASDAQ Global Select Market

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

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

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

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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 the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates as of June 30, 2017 was $135.2 million. This amount is based on the closing price of the registrant's common stock on the NASDAQ Global Select Market on that date.

The number of shares of the registrant's common stock, par value $0.01, outstanding as of March 2, 2018, was 94,333,181.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's proxy statement for its 2018 annual meeting of stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2017, are incorporated by reference in Part III, Items 10-14 of this report.

Certain exhibits previously filed with the Securities and Exchange Commission are incorporated by reference into Part IV of this report.

APPROACH RESOURCES INC.

Unless the context otherwise indicates, all references in this report to “Approach,” the “Company,” “we,” “us,” “our” or “ours” to Approach Resources Inc. and its subsidiaries. Unless otherwise noted, (i) all information in this report relating to oil, NGLs and natural gas reserves and the estimated future net cash flows attributable to reserves is based on estimates and is net to our interest, and (ii) all information in this report relating to oil, NGLs and natural gas production is net to our interest. Natural gas is converted throughout this report at a rate of six Mcf of gas to one barrel of oil equivalent (“Boe”). NGLs are converted throughout this report at a rate of one barrel of NGLs to one Boe. The ratios of six Mcf of gas to one Boe and one barrel of NGLs to one Boe do not assume price equivalency and, given price differentials, the price for a Boe of natural gas or NGLs may differ significantly from the price of a barrel of oil. If you are not familiar with the oil and gas terms or abbreviations used in this report, please refer to the definitions of these terms and abbreviations under the caption “Glossary” after Item 16 of this report.

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Cautionary Statement Regarding Forward-Looking Statements

Various statements in this report, including those that express a belief, expectation or intention, as well as those that are not statements of historical fact, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the “Securities Act”), and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). The forward-looking statements may include projections and estimates concerning the timing and success of specific projects, typical well economics and our future reserves, production, revenues, costs, income, capital spending, 3-D seismic operations, interpretation and results and obtaining permits and regulatory approvals. When used in this report, the words “will,” “believe,” “intend,” “expect,” “may,” “should,” “anticipate,” “could,” “e “plan,” “predict,” “project,” “potential” or their negatives, other similar expressions or the statements that include those words, are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

These forward-looking statements are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management’s assumptions about future events may prove to be inaccurate. We caution all readers that the forward-looking statements contained in this report are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to the factors listed in the “Risk Factors” section and elsewhere in this report. All forward-looking statements speak only as of the date of this report. We disclaim any obligation to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise, unless required by law. These cautionary statements qualify all forward-looking statements attributable to us, or persons acting on our behalf. The risks, contingencies and uncertainties relate to, among other matters, the following:

- uncertainties in drilling, exploring for and producing oil and gas;
- oil, NGLs and natural gas prices;
- overall United States and global economic and financial market conditions;
- our leverage negatively affecting the semi-annual redetermination of our revolving credit facility and our ability to comply with the covenants in our revolving credit facility;
- domestic and foreign demand and supply for oil, NGLs, natural gas and the products derived from such hydrocarbons;
- actions of the Organization of Petroleum Exporting Countries (“OPEC”), its members and other state-controlled oil companies relating to oil price and production controls;
- our ability to obtain additional financing necessary to fund our operations and capital expenditures and to meet our other obligations;
- our ability to maintain a sound financial position;
- issuance of our common stock in connection with potential refinancing transactions that may cause substantial dilution;
- our cash flows and liquidity;
- the effects of government regulation and permitting and other legal requirements, including laws or regulations that could restrict or prohibit hydraulic fracturing;
- disruption of credit and capital markets;
- disruptions to, capacity constraints in or other limitations on the pipeline systems that deliver our oil, NGLs and natural gas and other processing and transportation considerations;
- marketing of oil, NGLs and natural gas;

- high costs, shortages, delivery delays or unavailability of drilling and completion equipment, materials, labor or other services;
- competition in the oil and gas industry;
- uncertainty regarding our future operating results;
- profitability of drilling locations;
- interpretation of 3-D seismic data;
- replacing our oil, NGLs and natural gas reserves;
- our ability to retain and attract key personnel;
- our business strategy, including our ability to recover oil, NGLs and natural gas in place associated with our Wolfcamp shale oil resource play in the Permian Basin;
- development of our current asset base or property acquisitions;
- estimated quantities of oil, NGLs and natural gas reserves and present value thereof;
- plans, objectives, expectations and intentions contained in this report that are not historical; and
- other factors discussed under Item 1A. “Risk Factors” in this report.

PART I

ITEM 1. BUSINESS

General

Approach Resources Inc. is an independent energy company focused on the exploration, development, production and acquisition of unconventional oil and gas reserves in the Midland Basin of the greater Permian Basin in West Texas, where we lease approximately 149,000 net acres as of December 31, 2017. We believe our concentrated acreage position and extensive, integrated field infrastructure system provides us an opportunity to achieve cost, operating and recovery efficiencies in the development of our drilling inventory. Our long-term business strategy is to develop resource potential from the Wolfcamp shale oil formation and pursue acquisitions that meet our strategic and financial objectives. See "— Our Business Strategy" below. Additional drilling targets could include the Clearfork, Canyon Sands, Strawn and Ellenburger zones. We sometimes refer to our development project in the Permian Basin as "Project Pangea," which includes "Pangea West." Our management and technical team have a proven track record of finding and developing reserves through advanced drilling and completion techniques. As the operator of all of our estimated proved reserves and production, we have a high degree of control over capital expenditures and other operating matters.

At December 31, 2017, our estimated proved reserves were 181.5 million barrels of oil equivalent ("MMBoe"). Substantially all of our proved reserves are located in Crockett and Schleicher Counties, Texas. The following are important characteristics of our proved reserves at December 31, 2017:

- 28% oil, 32% NGLs and 40% natural gas;
- 37% proved developed;
- 100% operated;
- Reserve life of approximately 43 years based on 2017 production of 4.2 MMBoe;
- Standardized measure of discounted future net cash flows ("standardized measure") of $461 million; and
- PV-10 (non-GAAP) of $521 million.

PV-10 is our estimate of the present value of future net revenues from proved oil, NGLs and natural gas reserves after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates for future income taxes. Estimated future net revenues are discounted at an annual rate of 10% to determine their present value. PV-10 is a financial measure that is not determined in accordance with accounting principles generally accepted in the United States ("GAAP"), and generally differs from the standardized measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future cash flows. PV-10 should not be considered as an alternative to the standardized measure, as computed under GAAP. See Item 2. "Properties — Proved Oil and Gas Reserves" for a reconciliation of PV-10 to the standardized measure.

At December 31, 2017, we owned and operated 813 producing oil and gas wells in the Permian Basin. During 2017, we produced 4.2 MMBoe, or 11.6 MBoe/d. Production for 2017 was 26% oil, 35% NGLs and 39% natural gas.

Our History

Approach Resources Inc. was incorporated in September 2002. Our common stock began trading on the NASDAQ Global Market in the United States under the symbol "AREX" on November 8, 2007, and is now listed on the NASDAQ Global Select Market ("NASDAQ"). Our principal executive offices are located at One Ridgmar Centre, 6500 West Freeway, Suite 800, Fort Worth, Texas 76116. Our telephone number is (817) 989-9000.

Our Business Strategy

Our long-term business strategy is to create value by growing reserves and production in a cost efficient manner and at attractive rates of return by pursuing the strategies discussed below. However, the rate of growth of our reserves and production, as well as achievable rates of return, depend on commodity prices. In response to depressed and volatile commodity prices we substantially reduced our drilling activity beginning in 2015 and throughout 2016, which led to a natural decline in production. Commodity prices remained volatile, but improved in 2017. We have positioned ourselves to increase our drilling activity at a measured and disciplined pace, and resume production growth in the event of a continued commodity price recovery, by focusing on the following strategies:

- Develop our Wolfcamp shale oil resource play. We believe our current acreage position provides us the long-term ability to increase reserves and production at competitive costs and at attractive rates of return in an improving commodity price environment. During 2017, we drilled 13, and completed nine, horizontal Wolfcamp wells, and entered 2018 with an inventory of 10 drilled horizontal wells waiting on completion. With our 2018 drilling plan, we expect to continue to develop our core properties in Project Pangea. Focusing on the Wolfcamp shale oil play allows us to use our operating, technical and regional expertise important to interpreting geological and operating trends, enhancing production rates and maximizing well recovery. In addition, our inventory of drilled wells waiting on completion allows us to increase production with lower marginal capital expenditures.
- Operate our properties as a low-cost producer. We believe our concentrated acreage position in the Midland Basin enables us to capture economies of scale and operating efficiencies. Through our investment in extensive integrated field infrastructure, including water transportation and recycling systems, centralized production facilities, gas lift lines and salt water disposal wells, we have significantly reduced drilling and completion costs, per-unit lease operating expenses and our fresh water use over the last three years. In addition, because we operate 100% of our reserve base, we are able to better manage timing and scope of capital expenditures and control costs.
- Further strengthen our balance sheet and preserve financial flexibility. In November 2016, we entered into an exchange agreement (the "Exchange Agreement") with the largest holder of our 7% Senior Notes due 2021 (the "Senior Notes") under which we exchanged $130,552,000 principal amount of our Senior Notes for 39,165,600 newly issued shares of our common stock (the "Initial Exchange"). In March 2017, we exchanged an additional $14,528,000 principal amount of outstanding Senior Notes for 4,009,728 shares of our common stock (the "Follow-On Exchange"). The Initial Exchange and the Follow-On Exchange (together, the "Exchange Transactions") reduced interest payments by $44.3 million over the remaining term of the Senior Notes, which allowed us to increase our capital budget out of operating cash flow. Additionally, in December 2017, we extended the term on our revolving credit facility by one year to May 7, 2020, and reaffirmed our $325 million borrowing base.
- Acquire strategic and complementary assets. In 2017, we acquired, through an issuance of our common stock, producing Wolfcamp shale assets adjacent to our Project Pangea acreage (the "Bolt-On Acquisition"). The Bolt-On Acquisition included estimated proved developed reserves of 1.6 MMboe, 3,300 net acres held by production and 36,000 net undeveloped acres subject to a continuous development obligation. We will continue to review opportunities to acquire producing properties, undeveloped acreage and drilling prospects. We focus particularly on opportunities where we believe our operational efficiency, reservoir management and geological expertise in unconventional oil and gas properties will enhance value and performance. We remain focused on unconventional resource opportunities, but we will also look at conventional opportunities based on individual project economics.
- Operate our business at or near cash-flow breakeven. In 2018, we have set our expected capital expenditure budget to a range of $50 million to $70 million in response to improved operating cash flow due to higher commodity prices and reduced interest expense. We believe that over the long term we will be able to maintain and grow production substantially out of operating cash flow. We have the operational flexibility to adjust our capital spending upward in response to a continued commodity price recovery. Operating our business at or near operating cash flow allows us to preserve liquidity so that we will be able to accelerate execution of our long-term strategy should commodity prices further recover. Because we operate 100% of our reserve base, we also have the flexibility to adjust our capital budget downward in response to commodity price decreases.

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- Mitigate commodity price volatility. We enter into commodity derivative contracts to partially mitigate the risk of commodity price volatility. For 2017, we hedged approximately 85%, 54% and 30% of our natural gas, NGLs and oil production, respectively. For 2018, we currently have 627,500 Bbls of oil hedged at a weighted average floor price of $56.37 per Bbl and a weighted average ceiling price of $57.81 per Bbl, 5,400,000 MMBtu of gas hedged at a weighted average price of $3.08 per MMBtu and 749,400 Bbls of NGLs hedged at weighted average prices of $11.42 per Bbl (C2-ethane), $32.53 per Bbl (C3-propane), $37.81 per Bbl (IC4-isobutane), $37.80 per Bbl (NC4-butane) and $56.36 per Bbl (C5 – Pentane).

Our Competitive Strengths

We have a number of competitive strengths, which we believe will help us to successfully execute our business strategies:

- Lower-risk, liquids-rich asset base. We have assembled a strong asset base within the Midland Basin, where we have a long history of operating. We have drilled more than 800 wells in the area since 2004. Our acreage position of 149,000 net, primarily contiguous acres in the Midland Basin provides us with a multi-year inventory of repeatable, horizontal and vertical drilling locations that we believe create the opportunity for us to deliver long-term reserve, production and cash flow growth. Production for 2017 was 61% liquids (26% oil and 35% NGLs) and 39% natural gas. With a liquids-rich but diverse production base, we are able to capture the upside of improvement in commodity prices in any one of our three production streams.
- High degree of operational control. We operate 100% of our estimated proved reserves, and we have approximately 98.5% working interest in Project Pangea. This allows us to more effectively manage and control the timing of capital spending on our development activities, as well as maximize benefits from operating cost efficiencies and field infrastructure systems.
- Proactive financial management. In 2017, we reduced the outstanding principal of our long-term debt by $127.1 million, extended the term on our revolving credit facility by one year to May 7, 2020, and completed the Bolt-On Acquisition. As of December 31, 2017, we had liquidity of approximately $33.7 million. In addition, we are committed to a disciplined capital program and improving our operating cash flow. We also enter into commodity derivative contracts to partially mitigate the risk of commodity price volatility.
- Experienced management team with track record of growth. Our management team has extensive industry experience, including significant technical and exploration expertise. Our management team has specific expertise in the Permian Basin and in successfully executing multi-year development drilling programs.

2017 Activity

Our 2017 activity focused on increasing our capital expenditures in a disciplined manner in connection with slowly recovering commodity prices, strengthening our balance sheet and increasing our operating cash flow. We drilled 13, and completed nine, horizontal wells in 2017 in the Wolfcamp shale oil resource play in the Midland Basin. We plan to continue to develop the Wolfcamp shale in Project Pangea in 2018, at a measured pace subject to commodity prices. Our 2017 activities included:

- Managed production decline and positioned to resume production growth. In response to depressed and volatile commodity prices we substantially reduced our drilling activity beginning in 2015 and throughout 2016, which led to a natural decline in production. In the first quarter of 2017, our production averaged 11.4 MBoe/d. Throughout 2017, we increased the pace of our drilling activity, and our production averaged 11.7 MBoe/d for the remainder of the year. Production for 2017 totaled 4.2 MMBoe (11.6 MBoe/d), compared to 4.5 MMBoe (12.4 MBoe/d) in 2016. Production for 2017 was 26% oil, 35% NGLs and 39% natural gas. At December 31, 2017, 10 horizontal wells were waiting on completion.

- Increased operating cash flow. In 2017, improved commodity prices and the Exchange Transactions resulted in an increase in operating cash flow by $11.4 million or 44%, which was used to fund our expanded drilling program in 2017.
- Delineation of the multi-zone potential of the Wolfcamp shale. The Wolfcamp shale has a gross pay thickness of approximately 1,000 to 1,200 feet, which allows for stacked wellbores targeting three different zones that we call “benches.” We believe effectively developing the Wolfcamp shale may involve up to three lateral wellbores, each targeting a different bench, which we refer to as the Wolfcamp A, B and C. As of December 31, 2017, we had drilled and completed a total of 18 wells targeting the Wolfcamp A bench, 110 wells targeting the Wolfcamp B bench and 50 wells targeting the Wolfcamp C bench. We have successful wells targeting each of the Wolfcamp benches, and we continued development of the Wolfcamp shale in 2017.
- Installation of field infrastructure and water handling systems. Our large, mostly contiguous acreage position and our success in the Wolfcamp shale oil play led us to invest over $120 million in building field infrastructure since 2012. We now have an extensive network of centralized production facilities, water transportation, handling and recycling systems, gas lift lines and salt water disposal wells. In addition, we believe the infrastructure reduces the need for trucks, reduces fresh water usage, improves drilling and completion efficiencies and drives down drilling and completion and operating costs. We were able to reduce our lease operating expenses by 7% or $1.3 million, in 2017, partially due to this infrastructure investment.

Plans for 2018

For 2018, we increased our capital expenditure budget to a range of $50 million to $70 million, compared to $47.1 million of capital expenditures in 2017. We plan to operate one rig on an intermittent basis during the year in Project Pangea. Our 2018 capital budget excludes acquisitions and lease extensions and renewals and is subject to change depending upon a number of factors, including prevailing and anticipated prices for oil, NGLs and gas, results of horizontal drilling and completions, economic and industry conditions at the time of drilling, the availability of sufficient capital resources for drilling prospects, our financial results and the availability of lease extensions and renewals on reasonable terms. Although the impact of changes in these collective factors in the current commodity price environment is difficult to estimate, we currently expect to execute our development plan based on current conditions. To the extent there is a significant increase or decrease in commodity prices in the future, we will assess the impact on our development plan at that time, and we may respond to such changes by altering our capital budget or our development plan.

Markets and Customers

The revenues generated by our operations are highly dependent upon the prices of oil, NGLs and natural gas. Oil, NGLs and natural gas are commodities, and therefore, we receive market-based pricing. The price we receive for our oil, NGLs and natural gas production depends on numerous factors beyond our control, including supply and demand for oil, NGLs and gas, seasonality, the condition of the domestic and global economies, particularly in the manufacturing sectors, political conditions in other oil and gas producing countries, the extent of domestic production and imports of oil, NGLs and gas, the proximity and capacity of gas pipelines and other transportation facilities, the marketing of competitive fuels and the effects of federal, state and local regulation. The oil and gas industry also competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers.

For the year ended December 31, 2017, sales to American Midstream, LP (“AMID”) and DCP Midstream, LP (“DCP”) accounted for approximately 52% and 47%, respectively, of our total sales. As of December 31, 2017, we had dedicated the majority of our oil production from northern Project Pangea and Pangea West through September 2022 to AMID. In addition, as of December 31, 2017, we had dedicated the majority of our NGLs and natural gas production from Project Pangea to DCP through August 2023.

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Commodity Derivative Activity

We enter into commodity swap and collar contracts to mitigate portions of the risk of market price fluctuations related to future oil, NGLs and gas production. Our derivative contracts are recorded as derivative assets and liabilities at fair value on our balance sheet, and the change in a derivative contract’s fair value is recognized as current income or expense on our consolidated statements of operations.

In 2017, we recognized a commodity derivative loss of $0.3 million, and the estimated fair value of our derivatives contracts at December 31, 2017, was a net liability of $0.8 million. For 2018, we currently have 627,500 Bbls of oil hedged at a weighted average floor price of $56.37 per Bbl and a weighted average ceiling price of $57.81 per Bbl, 5,400,000 MMBtu of gas hedged at a weighted average price of $3.08 per MMBtu and 749,400 Bbls of NGLs hedged at weighted average prices of $11.42 per Bbl (C2-ethane), $32.53 per Bbl (C3-propane), $37.81 per Bbl (IC4-isobutane), $37.80 per Bbl (NC4-butane) and $56.36 per Bbl (C5 – Pentane).

Title to Properties

Our properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions. We do not believe that any of these burdens materially interfere with our use of the properties in the operation of our business.

We believe that we generally have satisfactory title to or rights in all of our producing properties. As is customary in the oil and gas industry, we make a general investigation of title at the time we acquire undeveloped properties. We receive title opinions of counsel before we commence drilling operations. We believe that we have satisfactory title to all of our other assets. Although title to our properties is subject to encumbrances in certain cases, we believe that none of these burdens will materially detract from the value of our properties or from our interest therein or will materially interfere with our use of the properties in the operation of our business.

Oil and Gas Leases

The typical oil and natural gas lease agreement covering our properties provides for the payment of royalties to the mineral owner for all oil, NGLs and natural gas produced from any wells drilled on the leased premises. The lessor royalties and other leasehold burdens on our properties generally range from 20% to 25%, resulting in a net revenue interest to us generally ranging from 80% to 75%.

Seasonality

Demand for NGLs and natural gas generally decreases during the spring and fall months and increases during the summer and winter months. However, seasonal anomalies such as mild winters or mild summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. These seasonal anomalies can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations.

Competition

The oil and gas industry is highly competitive, and we compete for personnel, prospective properties, producing properties and services with a substantial number of other companies that have greater resources. Many of these companies explore for, produce and market oil and gas, carry on refining operations and market the end products on a worldwide basis. We also face competition from alternative fuel sources, including coal, heating oil, imported LNG, nuclear and other nonrenewable fuel sources, and renewable fuel sources such as wind, solar, geothermal, hydropower and biomass. Competitive conditions may also be substantially affected by various forms of energy legislation and/or regulation considered from time-to-time by the United States government. It is not possible to predict whether such legislation or regulation may ultimately be adopted or its precise effects upon our future operations. Such laws and regulations may, however, substantially increase the costs of exploring for, developing or producing oil, NGLs and gas and may prevent or delay the commencement or continuation of our operations.

Hydraulic Fracturing

Hydraulic fracturing is an important process in oil and gas production and has been commonly used in the completion of unconventional oil and gas wells in shale and tight sand formations since the 1950s. Hydraulic fracturing involves the injection of water, sand and chemical additives under pressure into rock formations to stimulate oil and gas production. It is important to us because it provides access to oil and gas reserves that previously were uneconomical to produce.

We have used hydraulic fracturing to complete both horizontal and vertical wells in the Permian Basin. We engage third parties to provide hydraulic fracturing services to us for completion of these wells. While hydraulic fracturing is not required to maintain our leasehold acreage that is currently held by production from existing wells, it will be required in the future to develop the proved undeveloped reserves associated with this acreage. All of our proved undeveloped reserves associated with future drilling will require hydraulic fracturing.

We believe we have followed, and intend to continue to follow, applicable industry standard practices and legal requirements for groundwater protection in our operations. These protective measures include setting surface casing at a depth sufficient to protect fresh water zones as determined by applicable state regulatory agencies and cementing the well to create a permanent isolating barrier between the casing pipe and surrounding geological formations. This aspect of well design is intended to prevent contact between the fracturing fluid and any aquifers during the hydraulic fracturing operations. For recompletions of existing wells, the production casing is pressure-tested before perforating the new completion interval.

Injection rates and pressures are monitored at the surface during our hydraulic fracturing operations. Pressure is monitored on both the injection string and the immediate annulus to the injection string. We believe we have adequate procedures in place to address abrupt changes to the injection pressure or annular pressure.

Texas regulations currently require disclosure of the components in the solutions used in hydraulic fracturing operations. More than 99% (by mass) of the ingredients we use in hydraulic fracturing are water and sand. The remainder of the ingredients are chemical additives that are managed and used in accordance with applicable requirements in Texas.

Hydraulic fracturing requires the use of a significant amount of water. Currently our primary sources of water in Project Pangea are the nonpotable Santa Rosa and potable Edwards-Trinity (Plateau) aquifers. We use water from on-lease water wells that we have drilled, and we purchase water from off-lease water wells. We have historically reused and recycled flowback and produced water and intend to do so in the future. Any flowback water that is not recycled in a way that we believe minimizes the impact to nearby surface water is disposed into approved disposal facilities or injection wells.

For information regarding existing and proposed governmental regulations regarding hydraulic fracturing and related environmental matters, please read “Business — Regulation — Environmental Laws and Regulation.” For related risks to our stockholders, please read “Risk Factors — Federal and state legislation and regulatory initiatives and private litigation relating to hydraulic fracturing could stop or delay our development project and result in materially increased costs and additional operating restrictions;” “— Our operations substantially depend on the availability of water. Restrictions on our ability to obtain, dispose of or recycle water may impact our ability to execute our drilling and development plans in a timely or cost-effective manner”; “— Climate change legislation or regulations regulating emissions of greenhouse gases (“GHGs”) and volatile organic compounds (“VOCs”) could result in increased operating costs and reduced demand for the oil and gas we produce”; and “—Environmental laws and regulations may expose us to significant costs and liabilities.”

Regulation

The oil and gas industry in the United States is subject to extensive regulation by federal, state and local authorities. At the federal level, various federal rules, regulations and procedures apply, including those issued by the U.S. Department of Interior, the U.S. Department of Transportation (the “DOT”) (Office of Pipeline Safety), the Occupational Safety and Health Administration (“OSHA”) and the U.S. Environmental Protection Agency (the “EPA”). At the state and local level, various agencies and commissions regulate drilling, production and midstream activities. These federal, state and local authorities have various permitting, licensing and bonding requirements. Various remedies are available for enforcement of these federal, state and local rules, regulations and procedures, including fines, penalties, revocation of permits and licenses, actions affecting the value of leases, wells or other assets, suspension of production, and, in certain cases, criminal prosecution. As a result, there can be no assurance that we will not incur liability for fines, penalties or other remedies that are available to these federal, state and local authorities. However, we believe that we are currently in substantial compliance with federal, state and local rules and regulations, and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations.

Transportation and Sale of Oil

Sales of crude oil and condensate are not currently regulated and are made at negotiated prices. Our sales of crude oil are affected by the availability, terms and cost of transportation. Interstate transportation of oil by pipeline is regulated by the Federal Energy Regulation Commission ("FERC") pursuant to the Interstate Commerce Act ("ICA"), Energy Policy Act of 1992 ("EPAct 1992"), and the rules and regulations promulgated under those laws. The ICA and its regulations require that tariff rates for interstate service on oil pipelines, including interstate pipelines that transport crude oil and refined products, be just and reasonable and non-discriminatory and that such rates, terms and conditions of service be filed with FERC.

Intrastate oil pipeline transportation rates are also subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. As effective interstate and intrastate rates apply equally to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our similarly situated competitors.

The transportation of oil by truck is also subject to federal, state and local rules and regulations, including the Federal Motor Carrier Safety Act and the Homeland Security Act of 2002. Regulations under these statutes cover the security and transportation of hazardous materials and are administered by the DOT.

Transportation and Sale of Natural Gas and NGLs

FERC regulates interstate gas pipeline transportation rates and service conditions under the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and regulations issued under those statutes. FERC also regulates interstate NGLs pipelines under various federal laws and regulations. Although FERC does not regulate oil and gas producers such as Approach, FERC's actions are intended to facilitate increased competition within all phases of the oil and gas industry and its regulation of third-party pipelines and facilities could indirectly affect our ability to transport or market our production. To date, FERC's policies have not materially affected our business or operations.

Regulation of Production

Oil, NGLs and gas production is regulated under a wide range of federal and state statutes, rules, orders and regulations, as well as under requirements of local governmental authorities. State and federal statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. The state in which we operate, Texas, has regulations governing conservation matters, including provisions for the unitization or pooling of oil and gas properties, the establishment of maximum rates of production from oil and gas wells, the regulation of spacing, and requirements for plugging and abandonment of wells. Also, Texas imposes a severance tax on production and sales of oil, NGLs and gas within its jurisdiction. In addition to state and federal laws and regulations, local land use restrictions could restrict or prohibit the location and/or performance of well drilling. The failure to comply with these rules and regulations can result in substantial penalties, delays in operations, and increased costs of operations. Our competitors in the oil and gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Environmental Laws and Regulations

In the United States, the exploration for and development of oil and gas and the drilling and operation of wells, fields and gathering systems are subject to extensive federal, state and local laws and regulations governing environmental protection and the release of materials into the environment. These laws and regulations may, among other things:

- require the acquisition of various permits or authorizations before drilling and production begin;
- require the installation of expensive pollution controls or emissions monitoring equipment;
- restrict or require the reporting of the types, quantities and concentration of various substances that can be released into the environment or are managed in connection with oil and gas drilling, completion, production, storage, transportation and processing activities;
- suspend, limit or prohibit construction, drilling and other activities in certain lands lying within municipalities, wilderness, wetlands, endangered species habitat and other protected areas; and
- require remedial measures to mitigate and remediate pollution from historical and ongoing operations, such as the closure of waste pits and plugging of abandoned wells.

These laws, rules and regulations may also restrict the rate of oil and gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability.

Governmental authorities have the power to enforce compliance with environmental laws, regulations and permits, and violations are subject to injunction, as well as administrative, civil and criminal penalties. The effects of existing and future laws and regulations could have a material adverse impact on our business, financial condition and results of operations. The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. Any changes in environmental laws and regulations or re-interpretations of enforcement policies that result in more stringent and costly permitting, reporting, or waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our business, financial condition or results of operations. Moreover, accidental releases or spills and ground water or surface water contamination may occur in the course of our operations, and we may incur significant costs and liabilities as a result of such releases, spills or contamination, including any third-party claims for damage to property, natural resources or persons. We maintain insurance against costs of clean-up operations, but we are not fully insured against all such risks. While we believe that we are in substantial compliance with existing environmental laws and regulations and that continued compliance with current requirements would not have a material adverse effect on us, there is no assurance that this will continue in the future.

The following is a summary of some of the existing environmental laws, rules and regulations that apply to our business operations. It remains unclear what actions, if any, the Trump administration will undertake related to these laws, rules and regulations.

Hazardous Substance Release

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 (“CERCLA”), also known as the Superfund law, and comparable state statutes impose strict liability, and under certain circumstances, joint and several liability, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site, regardless of whether the disposal of hazardous substances was lawful at the time of the disposal. Under CERCLA, such persons may be subject to strict, joint and several liabilities for the costs of investigating releases of hazardous substances, cleaning up the hazardous substances that have been released into the environment, damages to natural resources and certain health studies. In addition, it is not uncommon for neighboring landowners and other third-parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment as a result of oil and gas operations. Crude oil and fractions of crude oil are excluded from regulation under CERCLA (often referred to as the “petroleum exclusion”). Nevertheless, many chemicals commonly used at oil and gas production facilities fall outside of CERCLA's petroleum exclusion. While we generate materials in the course of our operations that may be regulated as hazardous substances, we have not received notification that we may be responsible for cleanup costs under CERCLA.

Waste Handling

The Resource Conservation and Recovery Act ("RCRA") and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the authorization and oversight of the EPA, individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. The EPA also retains enforcement authority in any state-administered RCRA programs. Drilling fluids, produced water and many other wastes associated with the exploration, development and production of oil or gas are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain oil and gas exploration and production wastes now regulated as non-hazardous could be regulated under RCRA as hazardous wastes in the future. Any such change could increase our operating expenses, which could have a material adverse effect on our business, financial condition and results of operations.

We currently own or lease properties that for many years have been used for oil and gas exploration, production and development activities. Although we used operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or wastes may have been disposed of or released on, under or from the properties owned or leased by us or on, under or from other locations where such wastes have been taken for disposal. In addition, some of these properties have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons and wastes was not under our control. These properties and the materials disposed or released on, at, under or from them may be subject to CERCLA, RCRA and analogous state laws or other laws that regulate releases or waste from oil and gas operations. Under such laws, we could be required to remove or remediate previously disposed wastes or contamination, or to perform remedial activities to prevent future contamination.

Air Emissions

The federal Clean Air Act ("CAA") and comparable state laws regulate emissions of various air pollutants through air emissions, permitting programs and other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions at specified sources. For example, under the EPA's New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAP") regulations, since January 1, 2015, owners and operators of hydraulically fractured natural gas wells (wells drilled principally for the production of natural gas) have been required to use so-called "green completion" technology to recover natural gas that formerly would have been flared or vented. In 2016, the EPA issued additional rules for the oil and gas industry to reduce emissions of methane, VOCs and other compounds. These rules apply to certain sources of air emissions that were constructed, reconstructed, or modified after September 18, 2015. Among other things, the new rules impose green completion requirements on new hydraulically fractured or re-fractured oil wells and leak detection and repair requirements at well sites. We do not expect that the currently applicable NSPS or NESHAP requirements will have a material adverse effect on our business, financial condition or results of operations. However, any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permitting requirements or use specific equipment or technologies to control emissions. Our failure to comply with existing or new requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and, potentially, criminal enforcement actions. We believe that we currently are in substantial compliance with all air emissions regulations and that we hold all necessary and valid construction and operating permits for our current operations.

Greenhouse Gas Emissions

While Congress has, from time-to-time, considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal legislation, a number of states have taken legal measures to reduce emissions of GHGs through the planned development of GHG emission inventories and/or regional GHG cap-and-trade programs

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or other mechanisms. Most cap-and-trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels such as refineries and gas processing plants, to acquire and surrender emission allowances corresponding with their annual emissions of GHGs. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. Many states have enacted renewable portfolio standards, which require utilities to purchase a certain percentage of their energy from renewable fuel sources.

In response to findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, the EPA has adopted regulations under existing provisions of the federal CAA. The EPA has adopted two sets of rules regarding possible future regulation of GHG emissions under the CAA, one of which purports to regulate emissions of GHGs from motor vehicles and the other of which would regulate emissions of GHGs from large stationary sources of emissions, such as power plants or industrial facilities. The motor vehicle rule was finalized in 2010 and became effective in 2011, but it did not require immediate reductions in GHG emissions. In 2015, the EPA issued a final rule to limit carbon emissions from new power plants and simultaneously released a final rule to limit carbon emissions from existing power plants (the latter rule is also known as the “Clean Power Plan”). While these regulations are currently the subject of litigation and ongoing rulemaking, including a stay issued by the U.S. Supreme Court and a proposed repeal by the EPA, if the regulations ultimately are upheld or replaced, it could have a significant impact on the electrical generation industry and may favor the use of natural gas over other fossil fuels such as coal in new plants. In the past, the EPA has also indicated that it will propose new GHG emissions standards for refineries, but we do not know when the agency will issue specific regulations.

In 2010, the EPA enacted final rules on mandatory reporting of GHGs. The EPA has also subsequently issued amendments to the rules containing technical and clarifying changes to certain GHG reporting requirements. Under the GHG reporting rules, certain onshore oil and natural gas production, processing, transmission, storage and distribution facilities are required to report their GHG emissions on an annual basis. Our operations in the Permian Basin are subject to the EPA’s mandatory GHG reporting rules, and we believe that we are in substantial compliance with such rules. We do not expect that the EPA’s mandatory GHG reporting requirements, as currently promulgated, will have a material adverse effect on our business, financial condition or results of operations.

The adoption of additional legislation or regulatory programs to monitor, permit, or reduce GHG emissions could require us to incur increased operating costs to comply with those requirements, such as costs to purchase and operate emissions control systems, acquire emissions allowances or obtain permits. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce GHG emissions could have an adverse effect on our future business, financial condition and results of operations.

Water Discharges

The Federal Water Pollution Control Act (the “Clean Water Act” or “CWA”) and analogous state laws, impose restrictions and strict controls on the discharge of pollutants and fill material, including spills and leaks of oil and other substances, into regulated waters, including wetlands. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA, an analogous state agency, or, in the case of fill material, the United States Army Corps of Engineers. Spill prevention, control, and countermeasure regulations promulgated under the CWA impose obligations and liabilities related to the prevention of oil spills and damages resulting from such spills into or threatening waters of the United States or adjoining shorelines. For example, operators of certain oil and natural gas facilities that store oil in more than threshold quantities, the release of which could reasonably be expected to reach jurisdictional waters, must develop, implement, and maintain Spill Prevention, Control, and Countermeasure Plans (“SPCC”). Where applicable to our operations, we prepare and implement SPCC

Plans to prevent releases of oil from our facilities or, if a release occurs, to mitigate the consequences of such release. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations.

In 2016, the EPA issued a final rule banning the disposal of wastewater from unconventional oil and gas wells to public wastewater and sewage treatment plants. Produced and other flowback water from our current operations in the Permian Basin is typically not discharged to wastewater treatment plants but is either re-injected into underground formations that do not contain potable water or recycled for reuse in our hydraulic fracturing operations.

The Safe Drinking Water Act, Groundwater Protection and the Underground Injection Control Program

Fluids associated with oil and gas production result from operations on the Company's properties and may be disposed by injection in underground disposal wells. The federal Safe Drinking Water Act ("SDWA") and the Underground Injection Control program (the "UIC program") promulgated under the SDWA and state programs regulate the drilling and operation of salt water disposal wells. The EPA has delegated administration of the UIC program in Texas to the Railroad Commission of Texas ("RRC"). Permits must be obtained before drilling salt water disposal wells, and casing integrity monitoring must be conducted periodically to ensure the casing is not leaking saltwater to groundwater. Contamination of groundwater by oil and gas drilling, production and related operations may result in fines, penalties and remediation costs, among other sanctions and liabilities under the SDWA and state laws. In addition, third-party claims may be filed by landowners and other parties claiming damages for alternative water supplies, property damages and bodily injury.

Currently, the Company believes that disposal well operations on its properties substantially comply with all applicable requirements under the SDWA and RRC rules. However, a change in the regulations or the inability to obtain permits for new disposal wells in the future may affect the Company's ability to dispose of produced waters and ultimately increase the cost of the Company's operations. For example, there exists a growing concern that the injection of salt water and other fluids into underground disposal wells triggers seismic activity in certain areas, including in some parts of Texas. In response to these concerns, in 2014, the RRC published a final rule governing permitting or re-permitting of disposal wells that would require, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections and structure maps relating to the disposal area in question. If the permittee or an applicant of a disposal well permit fails to demonstrate that the injected fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the RRC may deny, modify, suspend or terminate the permit application or existing operating permit for that well. These recent seismic permitting requirements applicable to disposal wells impose more stringent permitting requirements and are likely to result in added costs to comply or perhaps may require alternative methods of disposing of salt water and other fluids, which could delay production schedules and also result in increased costs.

Hydraulic Fracturing

Hydraulic fracturing is the subject of significant focus among some environmentalists, regulators and the general public. Concerns over potential hazards associated with the use of hydraulic fracturing and its impact on the environment have been raised at all levels, including federal, state and local, as well as internationally. There have been claims that hydraulic fracturing may contaminate groundwater, reduce air quality or cause earthquakes. Hydraulic fracturing requires the use and disposal of water, and public concern has been growing over the adequacy of the water supply.

The Energy Policy Act of 2005, which exempts hydraulic fracturing from regulation under the SDWA, prohibits the use of diesel fuel in the fracturing process without a UIC permit. In the past, legislation has been introduced in, but not passed by, Congress that would amend the SDWA to repeal this exemption. For example, the Fracturing Responsibility and Awareness of Chemicals Act ("FRAC Act") has been introduced in each chamber of Congress since 2009 to accomplish these purposes. If legislation repealing the exemption were enacted, it could require hydraulic fracturing operations to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting and recordkeeping obligations and meet plugging and abandonment requirements beyond those currently required by state regulatory agencies.

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In 2010, the EPA asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the UIC program by posting a requirement on its website that requires facilities to obtain permits to use diesel fuel in hydraulic fracturing operations. Following a legal challenge by industry groups and a subsequent settlement, in 2014, the EPA issued revised guidance on the use of diesel in hydraulic fracturing operations. Under the guidance, EPA broadly defined "diesel" to include fuels such as kerosene that have not traditionally been considered diesel. The EPA's continued assertion of its regulatory authority under the SDWA could result in extensive requirements that could cause additional costs and delays in the hydraulic fracturing process.

In addition to the above actions of the EPA, certain members of Congress have, in the past, called upon government agencies to investigate various aspects of hydraulic fracturing. Federal agencies that have been involved in hydraulic fracturing research include the White House Council on Environmental Quality, the Department of Energy, the Department of Interior and the Energy Information Administration. The EPA has also studied the potential environmental impacts of hydraulic fracturing on water resources, publishing a final report in 2016. These and future investigations and studies, depending on their degree of pursuit and any meaningful results obtained, could facilitate initiatives to further regulate hydraulic fracturing.

Some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances or otherwise require the public disclosure of chemicals used in hydraulic fracturing. For example, pursuant to legislation adopted by the State of Texas in 2011, the RRC enacted a rule requiring disclosure to the RRC and the public of certain information regarding additives, chemical ingredients, concentrations and water volumes used in hydraulic fracturing. In 2015, the Texas Legislature enacted House Bill 40, which prohibits local governments from prohibiting hydraulic fracturing but allows for commercially reasonable regulations of certain activities associated with oil and gas development. If future laws or regulations that significantly restrict hydraulic fracturing or that allow greater local government regulation of hydraulic fracturing are adopted, it could become more difficult or costly for us to drill and produce oil and gas from shale and tight sands formations and become easier for third parties opposing hydraulic fracturing to initiate legal proceedings. In addition, if hydraulic fracturing is regulated at the federal level, fracturing activities could become subject to delays, additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and higher costs. These new laws or regulations could cause us to incur substantial delays or suspensions of operations and compliance costs and could have a material adverse effect on our business, financial condition and results of operations.

Threatened and Endangered Species, Migratory Birds and Natural Resources

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

OSHA and Other Laws and Regulations

We are subject to the requirements of the federal OSHA and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used, produced or otherwise managed in our operations. These laws also require the development of risk management plans for certain facilities to prevent accidental releases of pollutants. We believe that we are in substantial compliance with these applicable requirements and with other OSHA and comparable requirements.

Compliance

We believe that we are in substantial compliance with all existing environmental laws and regulations that apply to our current operations and that our ongoing compliance with existing requirements will not have a material adverse effect on our business, financial condition or results of operations. We did not incur any material expenditures for remediation or pollution control activities for the year ended December 31, 2017. In addition, as of the date of this report, we are not aware of any environmental issues or claims that will require material capital or operating expenditures during 2018. However, the passage of additional or more stringent laws or regulations in the future could have a negative effect on our business, financial condition and results of operations, including our ability to develop our undeveloped acreage.

Employees

As of February 21, 2018, we had 97 full-time employees, 59 of whom are field personnel. We regularly use independent contractors and consultants to perform various field and other services. None of our employees are represented by a labor union or covered by any collective bargaining agreement. We believe that our relations with our employees are excellent.

Insurance Matters

As is common in the oil and gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because premium costs are considered prohibitive. A loss not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

Available Information

We maintain an internet website under the name www.approachresources.com. The information on our website is not a part of this report. We make available, free of charge, on our website, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports, as soon as reasonably practical after providing such reports to the SEC. Also, the charters of our Audit Committee, Compensation Committee and Nominating and Corporate Governance Committee, our Lead Independent Director Charter, our Governance Guidelines and our Code of Conduct are available on our website and in print to any stockholder who provides a written request to the Corporate Secretary at One Ridgmar Centre, 6500 West Freeway, Suite 800, Fort Worth, Texas 76116.

We file annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, proxy statements and other documents with the SEC under the Exchange Act. The public may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding issuers, including Approach, that file electronically with the SEC. The public can obtain any document we file with the SEC at www.sec.gov. Information contained on or connected to our website is not incorporated by reference into this Form 10-K and should not be considered part of this report or any other filing that we make with the SEC.

ITEM 1A. RISK FACTORS

You should carefully consider the risk factors set forth below as well as the other information contained in this report before investing in our common stock. Any of the following risks could materially and adversely affect our business, financial condition and results of operations. In such a case, you may lose all or part of your investment. The risks described below are not the only ones we face. Additional risks and uncertainties not currently known to us, or those we currently view as immaterial, may also materially adversely affect our business, financial condition and results of operations.

Drilling, exploring for and producing oil and gas are high-risk activities with many uncertainties that could adversely affect our business, financial condition and results of operations.

Our future financial condition and results of operations will depend on commodity prices and the success of our drilling, exploration and production activities. These factors are subject to numerous risks beyond our control, including the risk that drilling will not result in economic oil and gas production or increases in reserves. Many factors may curtail, delay or cancel our scheduled development projects, including:

- declines in oil, NGLs and gas prices;
- inadequate capital resources or liquidity to maintain current production levels or further develop our assets;
- compliance with governmental regulations, which may include limitations on hydraulic fracturing, access to water or the discharge of GHGs;
- limited transportation services and infrastructure to deliver the oil, NGLs and natural gas we produce to market;
- inability to attract and retain qualified personnel;
- unavailability or high cost of drilling and completion equipment, services or materials;
- unexpected drilling conditions, pressure or irregularities in formations, equipment failures or accidents;
- lack of acceptable prospective acreage;
- adverse weather conditions;
- surface access restrictions;
- title problems;
- mechanical difficulties;
- natural disasters; and
- civil unrest or protest activities.

Oil, NGLs and gas prices are volatile and have declined significantly in recent years. Sustained declines in oil, NGLs or gas prices from current levels would adversely affect our business, financial condition and results of operations and our ability to meet our capital expenditure requirements and financial commitments.

Our revenues, profitability and cash flow depend on the prices and demand for oil, NGLs and gas. The markets for these commodities are volatile, and even relatively modest drops in prices can affect significantly our financial results and impede our growth. Prices for oil, NGLs and gas fluctuate widely in response to changes in the supply and demand for these commodities, market uncertainty and a variety of additional factors beyond our control, such as:

- domestic and foreign supply of oil, NGLs and gas;
- domestic and foreign consumer demand for oil, NGLs and gas;
- overall United States and global economic conditions impacting the global supply of and demand for oil, NGLs and gas;
- actions of OPEC, its members and other state-controlled oil companies relating to oil price and production controls;
- commodity processing, gathering and transportation availability, the availability of refining capacity and other factors that result in differentials to benchmark prices;
- price and availability of alternative fuels;
- price and quantity of foreign imports;

- domestic and foreign governmental regulations;
- political conditions in or affecting other oil and natural gas producing countries;
- weather conditions, including unseasonably warm winter weather and tropical storms; and
- technological advances affecting oil, NGLs and gas consumption.

Advanced drilling and completion technologies, such as horizontal drilling and hydraulic fracturing, have resulted in increased investment by oil and gas producers in developing U.S. shale oil and gas projects and, therefore, has resulted in increased production from these projects. The results of higher investment in the exploration for and production of U.S. shale oil and gas, maintenance of production levels of oil from the Middle East, and other factors, such as global economic and financial conditions, have caused the price of oil and gas to be volatile. For example, prices for NYMEX-WTI ranged from a high of $60.42 per Bbl to a low of $42.53 per Bbl in 2017. NYMEX-Henry Hub natural gas prices ranged from a high of $3.72 per MMBtu to a low of $2.56 per MMBtu in 2017. While prices have increased from recent lows, they are still significantly below previous highs. Declines in oil and natural gas prices from current levels may further reduce our level of exploration, drilling and production activity and cash flows.

The Company’s financial position, results of operations, access to capital and the amount of oil and gas that may be economically produced would be negatively impacted if oil and gas prices decline from current levels for an extended period of time.

The ways that a decline in oil and gas prices from current levels could affect us include the following:

- Cash flows would be reduced, decreasing funds available for capital expenditures needed to maintain or increase production and replace reserves;
- We may breach covenants in our revolving credit facility;
- Future net cash flows from our properties would decrease, which could result in significant impairment expenses;
- Some reserves would no longer be economic to produce, leading to lower proved reserves, production and cash flows;
- Access to capital, such as equity or long-term debt markets and current reserve-based lending levels, would be severely limited or unavailable; and
- The borrowing base under our revolving credit facility could be reduced as further discussed below, and if the amount outstanding under our revolving credit facility exceeds the borrowing base, we may be required to repay a portion of our outstanding borrowings.

If commodity prices decline from current levels, our future cash flows will not be sufficient to fund the capital expenditure levels necessary to maintain current production and reserve levels over the long term and our results of operations will be adversely affected.

Low oil and gas prices not only cause our revenues and cash flows to decrease but also reduce the amount of oil and gas that we can produce economically. Decreases in oil and gas prices will render uneconomic some or all of our drilling locations. This may result in our having to impair our oil and gas properties further and could have a material adverse effect on our business, financial condition and results of operations. In addition, if oil, NGLs or gas prices further decline or fail to recover from their current levels for an extended period of time, we may, among other things, be unable to maintain or increase our borrowing capacity, repay current or future debt or obtain additional capital on attractive terms, all of which can affect the value of our common stock. The amount available for borrowing under our revolving credit facility is subject to a borrowing base, which is determined by our lenders taking into account our estimated proved reserves and is subject to semi-annual redeterminations based on pricing models determined by the lenders at such time. The decline in oil and gas prices has adversely impacted the value of our estimated proved reserves and, in turn, the market values used by our lenders to determine our borrowing base.

If we cannot significantly reduce our leverage, or we cannot increase our liquidity, we may seek alternative refinancing transactions.

We have been actively engaged in the process of analyzing various options to address our liquidity as well as assessing our overall capital structure. In 2017, we successfully closed the Exchange Transactions, which reduced the outstanding principal of our debt by $145.1 million. If we cannot continue to reduce our leverage with cash flow or through acquisitions, and if we cannot increase our liquidity, we may determine to evaluate additional transactions designed to reduce leverage and increase liquidity and operating cash flow. These transactions may not be advantageous to the existing holders of our common stock. Some of these alternatives may include additional debt buybacks, debt-for-debt or debt-for-equity exchanges or refinancings, strategic investments and joint ventures, sales of assets or working interests, private or public equity raises or rights offerings or transactions which may have a dilutive effect on our existing stockholders.

Wilks and its affiliates own a substantial portion of our outstanding common stock, and is entitled to appoint three of our directors, and thus it could exert certain significant influence over us, and their acquisition of additional common stock may cause a change in control.

As of January 12, 2018, Wilks Brothers, LLC and SDW Investments, LLC (collectively, “Wilks”) beneficially owned 45,239,713 shares of our common stock, representing approximately 48% of our outstanding common stock. In addition, pursuant to our stockholders agreement with Wilks, Wilks is entitled to appoint three of the seven members of our board of directors. As a result, Wilks could exert certain significant influence over us. Wilks may have interests that do not align with our interests and with the interests of our stockholders, which could have an adverse impact on our results of operations. In addition, Wilks’ level of control may make any potential takeover bids more costly or difficult in the future. Further, although Wilks is currently subject to a stockholders agreement that, among other things, caps their share ownership at 48.61% of our outstanding common stock, Wilks’ acquisition of more than 50% of our outstanding common stock would trigger change in control provisions in Company agreements, potentially causing severance payments to become due or the vesting of shares of common stock awards to be accelerated, and could cause a default under our revolving credit facility if the consent of certain lenders is not obtained, which could adversely affect the Company.

Our business requires significant capital expenditures, and we may not be able to obtain needed capital or financing on satisfactory terms or at all.

Our exploration, development and acquisition activities require substantial capital expenditures. For example, according to our year-end 2017 reserve report, the estimated future capital required to develop our current proved oil and gas reserves is $962.8 million. Historically, we have funded our capital expenditures through a combination of cash flows from operations, borrowings under our revolving credit facility and public equity and debt financings. In 2017, we funded our capital expenditures primarily through cash flows from operations. Future cash flows are subject to a number of variables, including the production from existing wells, prices of oil, NGLs and gas and our success in developing and producing new reserves. If commodity prices decline from current levels, our cash flow from operations may not be sufficient to cover our current or future capital expenditure budgets, and we may have limited ability to obtain the additional capital necessary to fully develop our proved reserves. In addition we may not be able to obtain debt or equity financing on favorable terms or at all. The failure to obtain additional financing could cause us to scale back our exploration and development operations, which in turn would lead to a decline in our oil and gas production and reserves, and in some areas a loss of properties.

We may not be able to generate enough cash flow to meet our debt obligations.

We expect our earnings and cash flow to vary significantly from year to year due to the nature of our industry. As a result, the amount of debt that we can manage in some periods may not be appropriate for us in other periods. Additionally, our future cash flow may be insufficient to meet our debt obligations and other commitments, including our obligations under our $85.2 million principal amount of Senior Notes and $291 million in outstanding borrowings under our revolving credit facility. A range of economic, competitive, business and industry factors will affect our future financial performance, and, as a result, our ability to generate cash flow from operations and to pay our debt. Many of these factors, such as oil and gas prices, economic and financial conditions in our industry and the global economy and initiatives of our competitors, are beyond our control. If we do not generate enough cash flow from operations to satisfy our debt obligations, we may have to undertake alternative financing plans, such as:

- selling assets;
- reducing or delaying capital investments;
- seeking to raise additional capital, potentially in a manner dilutive to our existing stockholders; or
- refinancing or restructuring our remaining debt.

If, for any reason, we are unable to meet our debt service and repayment obligations, we would be in default under the terms of the agreements governing our debt, which would allow our creditors at that time to declare all outstanding indebtedness to be due and payable, which could in turn trigger cross-acceleration or cross-default rights between the relevant agreements. In addition, our lenders could compel us to apply all of our available cash to repay our borrowings, or they could prevent us from making payments on the Senior Notes. If amounts outstanding under our revolving credit facility or the Senior Notes were to be accelerated, we cannot be certain that our assets would be sufficient to repay in full the money owed to the lenders or to our other debt holders.

Our lenders can limit our borrowing capabilities, which may materially impact our operations.

At December 31, 2017, we had $291 million in borrowings outstanding under our revolving credit facility, and our borrowing base was $325 million. The borrowing base under our revolving credit facility is redetermined semi-annually based upon a number of factors, including commodity prices and reserve levels. In addition to such semi-annual redeterminations, our lenders may request one additional redetermination during any 12-month period. Upon such redetermination, our borrowing base could be reduced, and if the amount outstanding under our revolving credit facility at any time exceeds the borrowing base at such time, we may be required to repay a portion of our outstanding borrowings. If commodity prices decrease significantly, it is likely that our borrowing base will be reduced after redetermination. We use cash flow from operations and bank borrowings to fund our exploration, development and acquisition activities. A reduction in our borrowing base could limit those activities. In addition, we may significantly change our capital structure to cover our working capital needs, make future acquisitions or develop our properties. Changes in capital structure may significantly increase our debt. If we incur additional debt for these or other purposes, the related risks that we now face could intensify. A higher level of debt also increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of debt depends on our future performance, which is affected by general economic conditions and financial, business and other factors, many of which are beyond our control.

Our revolving credit facility borrowing base is subject to semi-annual redetermination, and current Office of the Comptroller of the Currency (“OCC”) guidelines may incentivize lenders to limit our borrowing capabilities.

In 2016, the OCC issued revised guidelines for exploration and production companies that specify target leverage metrics that we currently exceed. The lower a loan’s credit rating, the more reserves a bank must set aside. This makes it more expensive for the bank to keep a negatively-rated, or classified, loan on its books. We continue to operate with leverage in excess of OCC guidelines, which increases our risk of a negative semi-annual borrowing base redetermination, which could in turn materially decrease our liquidity or cause our borrowings to exceed our borrowing base and cause us to be in default under our credit agreement.

Our revolving credit facility contains operating and financial restrictions and covenants that may restrict our business and financing activities or that economic conditions and commodity prices may cause us to breach.

Our revolving credit facility contains, and any future indebtedness we incur may contain, a number of restrictive covenants that will impose significant operating and financial restrictions on us, including restrictions on our ability to, among other things:

- sell assets, including equity interests in our subsidiaries;
- consolidate, merge or transfer all or substantially all of our assets;
- incur or guarantee additional indebtedness or issue preferred stock;
- redeem or prepay other debt;
- pay distributions on, redeem or repurchase our common stock or redeem or repurchase our subordinated debt;
- create or incur certain liens;
- make certain acquisitions and investments;
- enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us;
- engage in transactions with affiliates;
- create unrestricted subsidiaries;
- enter into financing transactions; and
- engage in certain business activities.

As a result of these covenants, we will be limited in the manner in which we conduct our business, and we may be unable to engage in favorable business activities or finance future operations or capital needs.

Our revolving credit facility also contains financial covenants. Our ability to comply with some of the covenants and restrictions contained in our revolving credit facility may be affected by events beyond our control. If commodity prices decline from current levels, our ability to comply with these covenants may be impaired. A failure to comply with the covenants, ratios or tests in our revolving credit facility, or any future indebtedness could result in an event of default, which, if not cured or waived, could have a material adverse effect on our business, financial condition and results of operations. If an event of default under our revolving credit facility occurs and remains uncured, the lenders:

- would not be required to lend any additional amounts to us;
- could elect to declare all borrowings outstanding, together with accrued and unpaid interest and fees, to be due and payable;
- may have the ability to require us to apply all of our available cash to repay these borrowings; or
- may prevent us from making debt service payments under our other agreements.

Failure to comply with any of the financial covenants contained in our revolving credit facility could cause an event of default and have a material adverse effect on our business.

Following the fourth amendment to our revolving credit facility, executed in December 2017, our credit facility includes three principal financial covenants: (i) an interest coverage ratio, (ii) a modified current ratio and (iii) a leverage ratio covenant that will first be measured in the first quarter of 2019. Failure to comply with these covenants could cause an event of default under our revolving credit facility and have a material adverse effect on our business.

See Note 3 to our consolidated financial statements in this report for a more detailed description of these financial covenants. As of December 31, 2017, we were in compliance with our interest coverage ratio covenant and our modified current ratio covenant. In order to satisfy the new leverage ratio covenant, we must improve our leverage ratio by the end of the first quarter of 2019. Factors beyond our control may affect our ability to comply with the leverage ratio covenant by the first quarter of 2019. Failure to comply with the financial covenants may result in an event of default.

Increases in interest rates could adversely affect our business, results of operations, cash flows from operations and financial condition.

Since all of the indebtedness outstanding under our revolving credit facility is at variable interest rates, we have significant exposure to increases in interest rates. As a result, our business, results of operations and cash flows may be adversely affected by significant increases in interest rates.

If commodity prices decline to a level such that our future undiscounted cash flows from our properties are less than their carrying value, we may be required to write down the carrying values of our properties. Additionally, current SEC rules also could require us to write down our proved undeveloped reserves in the future.

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. Based on prevailing commodity prices and specific market factors and circumstances at the time of 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 properties. A write-down is a non-cash charge to earnings. We recorded no impairment of our proved properties for the years ended December 31, 2017 and 2016. For the year ended December 31, 2015, we recorded an impairment loss of $220.2 million. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are taken. The risk that we will be required to write down the carrying value of our properties increases when oil and gas prices are low or volatile.

In addition, current SEC rules require that proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years, unless specific circumstances justify a longer time. This rule may limit our potential to book additional proved undeveloped reserves as we pursue our development projects. Moreover, we may be required to write down our proved undeveloped reserves if we do not drill those wells within the required timeframe or if commodity prices cause us to change our development plan to decrease the number of wells to be drilled over the five-year period. For example, for the year ended December 31, 2017, we reclassified 17.7 MMBoe of proved reserves to unproved reserves attributable to horizontal well locations in Project Pangea that are no longer expected to be developed within five years from their initial booking, as required by SEC rules.

The estimated volumes, standardized measure and present value of future net revenues (“PV-10”) from our proved reserves as of December 31, 2017, should not be considered as the current market value of the estimated oil and gas reserves attributable to our properties.

Standardized measure is a reporting convention that provides a common basis for comparing oil and gas companies subject to the rules and regulations of the SEC. On December 31, 2017, our standardized measure of discounted cash flows was $461 million. Standardized measure requires the use of specific pricing as required by the SEC as well as operating and development costs prevailing as of the date of computation. The non-GAAP financial measure, PV-10, is based on the average of the closing price on the first day of the month for the 12-month period prior to fiscal year end, while actual future prices and costs may be materially higher or lower.

Our estimated proved reserves as of December 31, 2017, and related standardized measure and PV-10, were calculated under the SEC rules using 12-month trailing average benchmark prices of $51.34 per Bbl of oil, $18.67 per Bbl of NGLs and $2.99 per MMBtu of gas. If oil, NGLs and gas prices decline by 10% from $51.34 per Bbl of oil, $18.67 per Bbl of NGLs and $2.99 per MMBtu of gas, to $46.21 per Bbl of oil, $16.80 per Bbl of NGLs and $2.69 per MMBtu of gas, then our PV-10 as of December 31, 2017, would decrease from $521 million to approximately $391 million. Actual future net revenues also will be affected by factors such as the amount and timing of actual production, prevailing operating and development costs, supply and demand for oil and gas, increases or decreases in consumption and changes in governmental regulations or taxation. For a reconciliation of PV-10, a measure not calculated in accordance with GAAP, to our standardized measure of discounted future cash flows and related disclosures, see “Reconciliation of PV-10 to Standardized Measure.”

Consequently, these measures may not reflect the prices ordinarily received or that will be received for oil and gas production because of varying market conditions, nor may they reflect the actual costs that will be required to produce or develop the oil and gas properties. Accordingly, estimates of future net cash flow may be materially different from the future net cash flows that are ultimately received. Therefore, the standardized measure of our estimated reserves and PV-10 included in this report should not be construed as accurate estimates of the current fair value of our proved reserves. In addition, the 10% discount factor we use when calculating PV-10 may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general.

The issuance of shares in the future could reduce the market price of our common stock.

In the future, we may issue common stock or other securities to raise cash for further debt and leverage reduction, working capital, acquisitions or hiring and retaining employees. We also may acquire interests in other companies by using a combination of cash and our common stock or just our common stock. We also may issue securities convertible into, or exchangeable for, or that represent the right to receive, our common stock. Any of these events may dilute your ownership interest in our company, reduce our earnings per share and have an adverse impact on the price of our common stock. In addition, sales or issuances of a substantial amount of our common stock, or the perception that these sales or issuances may occur, could reduce the market price of our common stock. This could also impair our ability to raise additional capital through the sale of our securities.

Our stock price has been and could remain volatile, which further could adversely affect the market price of our stock and our ability to raise additional capital and cause us to be subject to securities class action litigation.

The market price of our common stock has experienced and may continue to experience significant volatility. In 2017, the price of our common stock fluctuated from a high of $3.70 per share to a low of $1.93 per share. In addition, in recent years, the stock market has experienced significant price and volume fluctuations. This volatility has affected the market prices of securities issued by many companies in the energy sector, and particularly in the upstream sector. Such market price volatility could adversely affect our ability to raise additional capital. In addition, we may be subject to securities class action litigation as a result of the decline in the price of our common stock, which could result in substantial costs and diversion of management’s attention and resources and could harm our stock price, business, prospects, results of operations and financial condition.

We may experience differentials to benchmark prices in the future, which may be material.

Substantially all of our production is sold to purchasers at prices that reflect a discount to other relevant benchmark prices, such as NYMEX-WTI or NYMEX-Henry Hub. The price we receive for the majority of our natural gas is based on the price received by our third party midstream purchaser. Our third party midstream purchaser sells most of our natural gas at the WAHA hub in West Texas. The difference between a benchmark price and the price we reference in our sales contracts is called a basis differential. Basis differentials result from variances in regional prices compared to benchmark prices as a result of regional supply and demand factors. For example, the WAHA index price in December 2017 was $0.47 per MMBtu lower than the NYMEX-Henry Hub price. We may experience differentials to benchmark prices in the future, which may be material.

We engage in commodity derivative transactions which involve risks that can harm our business.

To manage our exposure to price risks in the marketing of our production, we enter into commodity derivative agreements. While intended to reduce the effects of volatile commodity prices, such transactions may limit our potential gains and increase our potential losses if commodity prices were to rise substantially over the price established by the commodity derivative. In addition, such transactions may expose us to the risk of loss in certain circumstances, including instances in which our production is lower than expected. We are also exposed to the risk of non-performance by the counterparties to the commodity derivative agreements.

Due to the enactment of the Dodd-Frank Wall Street Reform and Consumer Protection Act (“Dodd-Frank”), the derivative transactions we execute are undertaken in a highly regulated market. While many of the rules implementing the Dodd-Frank statute are in place at this time, some significant components of the Dodd-Frank regulatory regime remain subject to rulemaking by the Commodity Futures Trading Commission and other regulators.

Although we have hedged a portion of our estimated 2018 production, our hedging program may be inadequate to protect us against continuing and prolonged declines in the price of oil and natural gas.

Currently we have commodity price derivative agreements for 2018 production on approximately (i) 627,500 Bbls of oil with swaps and collars at a weighted average floor price of $56.37 per Bbl and a weighted average ceiling price of $57.81 per Bbl, (ii) 5,400,000 MMBtu of natural gas hedged with swaps at a weighted average price of $3.08 per MMBtu and (iii) 749,400 BBls of NGLs at weighted average prices of $11.42 per Bbl (C2-ethane), $32.53 per Bbl (C3-propane), $37.81 per Bbl (IC4-isobutane), $37.80 per Bbl (NC4-butane) and $56.36 per Bbl (C5-Pentane). These derivative contracts will not protect us from a continuing and prolonged decline in the price of oil and natural gas for the unhedged portion of our production in 2018 or our production after 2018. To the extent that the prices for oil and gas decline, 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.

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

Our oil and gas drilling, production and gathering operations are subject to complex and stringent laws and regulations. To operate in compliance with these laws and regulations, we must obtain and maintain numerous permits and approvals from various federal, state and local governmental authorities. We may incur substantial costs to comply with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations apply to our operations. Such costs could have a material adverse effect on our business, financial condition and results of operations. Failure to comply with laws and regulations applicable to our operations, including any evolving interpretation and enforcement by government authorities, could have a material adverse effect on our business, financial condition and results of operations. See “Business — Regulation” for a further description of the laws and regulations that affect us.

Federal and state legislation and regulatory initiatives and private litigation relating to hydraulic fracturing could stop or delay our development project and result in materially increased costs and additional operating restrictions.

All of our proved undeveloped reserves associated with future drilling and completion projects will require hydraulic fracturing. See Item 1. “Business — Hydraulic Fracturing” for a discussion of the importance of hydraulic fracturing to our business, and Item 1. “Business — Regulation —Hydraulic Fracturing” for a discussion of regulatory developments regarding hydraulic fracturing. If these or any other new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to drill and produce from our proved reserves, as well as make it easier for third parties opposing hydraulic fracturing to initiate legal proceedings. In addition, if hydraulic fracturing is regulated at the federal level, fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also permitting delays and increases in costs. The EPA and other federal agencies, including the United States Bureau of Land Management (“BLM”), have in recent years made proposals that would subject hydraulic fracturing to further regulation and could restrict the practice of hydraulic fracturing. For example, the EPA has issued final regulations under the federal Clean Air Act establishing performance standards for oil and gas activities, including standards for the capture of air emissions released during hydraulic fracturing, and, in 2016, the EPA finalized regulations that prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. Several of the EPA's and the BLM's recently promulgated rules concerning regulation of hydraulic fracturing are in various stages of suspension, implementation delay and court challenges, therefore, the future of these rules is uncertain. The EPA also released a study in December 2016 finding that certain aspects of hydraulic fracturing, such as water withdrawals and wastewater management practices, could result in impacts to water resources, although the report did not identify a direct link between hydraulic fracturing

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and impacts to groundwater resources. However, several states have adopted, and more states are considering adopting, laws and/or regulations that require disclosure of chemicals used in hydraulic fracturing and impose more stringent permitting, disclosure and well-construction requirements on hydraulic fracturing operations. In addition, some states and municipalities have significantly limited drilling activities and/or hydraulic fracturing, or are considering doing so. Although it is not possible at this time to predict the final outcome of these proposals or court challenges to existing rules or proposed rules, any new federal, state or local restrictions on hydraulic fracturing that may be imposed in areas in which we conduct business could cause us to incur substantial compliance costs, and compliance or the consequences of our failure to comply could have a material adverse effect on our financial condition and results of operations. In addition, if we are unable to use hydraulic fracturing in completing our wells or hydraulic fracturing becomes prohibited or significantly regulated or restricted, we could lose the ability to drill and complete the projects for our proved reserves and maintain our current leasehold acreage, which would have a material adverse effect on our future business, financial condition and results of operations.

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

Our industry is cyclical, and, from time-to-time, during periods of improving and high commodity prices, there is a shortage of drilling rigs, hydraulic fracturing services, equipment, supplies or qualified service personnel. During these periods, the costs and delivery times of equipment, oilfield services and supplies are substantially greater. In addition, the demand for, and wage rates of, qualified drilling and completion crews rise as the number of active rigs in service increases. Increasing levels of exploration and production will increase the demand for oilfield services, and the costs of these services may increase, while the quality of these services may suffer. If the availability of equipment, crews, materials and services in the Permian Basin is particularly severe, our business, results of operations and financial condition could be materially and adversely affected because our operations and properties are concentrated in the Permian Basin.

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

Water is an essential component of our drilling and hydraulic fracturing processes. Historically, we have been able to secure water from local landowners and other sources for use in our operations. From 2011 through 2014, West Texas experienced extreme drought conditions. As a result of the severe drought, governmental authorities restricted the use of water subject to their jurisdiction for drilling and hydraulic fracturing to protect the local water supply. Although such restrictions have been lifted, if West Texas experiences further drought conditions, the restrictions may return. If we are unable to obtain water to use in our operations, we may be unable to economically produce oil, NGLs and gas, which could have an adverse effect on our business, financial condition and results of operations.

Moreover, new environmental initiatives and regulations could include restrictions on disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of oil and gas. For example, in 2014, the RRC published a final rule governing permitting or re-permitting of disposal wells that would require, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections and structure maps relating to the disposal area in question. In 2016, the United States Geological Survey identified several states, including Texas, with areas of increased rates of induced seismicity that could be attributed to fluid injection or oil and gas extraction. Furthermore, ongoing lawsuits allege 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 by the Company or by commercial disposal well vendors whom the Company may use from time to time to dispose of produced water. Compliance with environmental regulations and permit requirements for the disposal, withdrawal, storage and use of surface water or ground water necessary for hydraulic fracturing may increase our operating costs and cause delays, interruptions or cessation of our operations, the extent of which cannot be predicted, and all of which would have an adverse effect on our business, financial condition and results of operations.

Conservation measures and technological advances could reduce demand for oil and gas.

Fuel conservation measures, alternative fuel requirements, increasing interest in alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and gas. The impact of the changing demand for oil and gas may have a material adverse effect on our business, financial condition and results of operations.

Climate change legislation or regulations regulating emissions of GHGs and VOCs could result in increased operating costs and reduced demand for the oil and gas we produce.

In response to findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, the EPA adopted regulations that restrict emissions of GHGs under existing provisions of the federal CAA. The EPA also issued final regulations under the NSPS and NESHAP designed to reduce VOCs, including methane. See Item 1. "Business — Regulation — Environmental Laws and Regulations — Greenhouse Gas Emissions" and " — Air Emissions" for a discussion of regulatory developments regarding GHG and VOC emissions.

While Congress has from time-to-time considered legislation to reduce emissions of GHGs, no significant legislation has been adopted to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of GHG cap-and-trade programs. Most of these cap-and-trade programs require either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. These allowances are expected to escalate significantly in cost over time.

In 2016, the EPA issued a final Information Collection Request seeking information about methane emissions from facilities and operators in the oil and gas industry. The EPA indicated that it intended to use the information from this request to develop Existing Source Performance Standards for the oil and gas industry or to develop standards for certain kinds of new and modified equipment and facilities not currently covered under the NSPS. Although the EPA rescinded the Information Collection Request in March 2017, the EPA could take additional actions to collect such information from individual operators or from the industry as a whole and rely upon such information as the basis for GHG emission regulation of the oil and gas industry.

The adoption of legislation or regulatory programs to reduce GHG or VOC emissions could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory requirements. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce GHG or VOC emissions could have a material adverse effect on our business, financial condition and results of operations.

Environmental laws and regulations may expose us to significant costs and liabilities.

There is inherent risk of incurring significant environmental costs and liabilities in our oil and gas operations due to the handling of petroleum hydrocarbons and generated wastes, the occurrence of air emissions and water discharges from work-related activities and the legacy of pollution from historical industry operations and waste disposal practices. We may incur joint and several or strict liability under these environmental laws and regulations in connection with spills, leaks or releases of petroleum hydrocarbons and wastes on, under or from our properties and facilities, some of which have been used for exploration, production or development activities for many years and by third parties not under our control. In particular, the number of private, civil lawsuits involving hydraulic fracturing has risen in recent years. Since 2009, multiple private lawsuits alleging ground water contamination have been filed in the U.S. against oil and gas companies, primarily by landowners who leased oil and gas rights to defendants, or by landowners who live close to areas where hydraulic fracturing has taken place. In addition, changes in environmental laws and regulations occur frequently, and any such changes that result in more stringent and costly waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our business, financial condition and results of operations. We may not be able to recover some or any of these costs from insurance.

Our ability to use our federal net operating loss carryforwards (“NOLs”) to offset future taxable income may be subject to certain limitations.

Under Section 382 of the Internal Revenue Code of 1986, as amended (the “Code”), a corporation that undergoes an “ownership change” is subject to limitations on its ability to use its pre-change NOLs to offset future taxable income. As a result of the Exchange Transactions, we underwent an ownership change under Section 382 as of March 22, 2017, which resulted in an annual limitation on our ability to use our pre-change NOLs to offset future taxable income recognized after such date. Accordingly, we reduced our NOL deferred tax assets by $139.1 million.

U.S. federal income tax reform could adversely affect us.

On December 22, 2017, President Trump signed into law the Tax Cuts and Jobs Act (the “TCJA”) that significantly reforms the Code. The TCJA, among other things, includes changes to U.S. federal tax rates and allows for the expensing of capital expenditures. While past legislative proposals have included changes to certain key U.S. federal income tax provisions currently available to oil and gas companies including (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, and (iii) an extension of the amortization period for certain geological and geophysical expenditures, these specific changes are not included in the TCJA. No accurate prediction can be made as to whether any such legislative changes will be proposed or enacted in the future or, if enacted, what the specific provisions or the effective date of any such legislation would be. However, the TCJA (i) eliminates the deduction for certain domestic production activities, (ii) imposes new limitations on the use of NOLs, (iii) limits the deductibility of performance based compensation to executive officers and (iv) provides for more general changes to the taxation of corporations, including changes to cost recovery rules and significant additional limitations on the deductibility of interest, which may impact the taxation of oil and gas companies. This legislation or any future changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that currently are available with respect to oil and gas development, or increase costs, and any such changes could have an adverse effect on our financial position, results of operations, and cash flows.

We do not expect tax reform to have a material impact to our projection of cash taxes or to our NOLs. Our net deferred tax assets and liabilities have been revalued at the newly enacted U.S. corporate rate, and the impact was recognized in our tax expense in the year of enactment. We continue to examine the impact this tax reform legislation may have on our business. The impact of this tax reform on holders of our common stock is uncertain and could be adverse.

Our future reserve and production growth depends on the success of our horizontal Wolfcamp oil shale resource play, which has a limited operational history and is subject to change.

We began drilling horizontal wells in the Wolfcamp play in late 2010. The wells that have been drilled or recompleted in these areas represent a small sample of our large acreage position, and we cannot assure you that our new wells will be successful. We continue to gather data about our prospects in the Wolfcamp play, and it is possible that additional information may cause us to change our drilling schedule or determine that prospects in some portion of our acreage position should not be developed at all.

Part of our strategy involves using some of the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

Our operations involve using some of the latest drilling and completion techniques as developed by us and our service providers. Risks that we face while drilling horizontal wells include, but are not limited to:

- landing our wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running our casing the entire length of the wellbore; and
- being able to run tools and other equipment consistently through the horizontal wellbore.

Risks that we face while completing our wells include, but are not limited to:

- the ability to fracture stimulate the planned number of stages;
- the ability to run tools the entire length of the wellbore during completion operations; and
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage.

The results of our drilling in new or emerging formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas have limited or no production history and, consequently, we are more limited in assessing future drilling results in these areas. If our drilling results are less than anticipated, the return on our investment for a particular project may not be as attractive as we anticipated and we could incur material write-downs of unevaluated properties and the value of our undeveloped acreage could decline in the future.

Failure to effectively execute and manage our single major development project, Project Pangea, could result in significant delays, cost overruns, limitation of our growth, damage to our reputation and a material adverse effect on our business, financial condition and results of operations.

We believe we have an extensive inventory of identified drilling locations in our development project (Project Pangea) in the Wolfcamp shale oil resource play; however, Project Pangea is our core asset and our only development project. As we achieve more results in Project Pangea, we have expanded our horizontal development project there. This level of development activity requires significant effort from our management and technical personnel and places additional requirements on our financial resources and internal operating and financial controls. Our ability to successfully develop and manage this project will depend on, among other things:

- our ability to finance development of the project;
- the extent of our success in drilling and completing horizontal Wolfcamp wells;
- our ability to control costs and manage drilling and completion risks;
- our ability to attract, retain and train qualified personnel with the skills required to develop the project in a timely and cost-effective manner; and
- our ability to implement and maintain effective operating and financial controls and reporting systems necessary to develop and operate the project.

We may not be able to compensate for, or fully mitigate, these risks.

Currently, substantially all of our producing properties are located in two counties in Texas, making us vulnerable to risks associated with operating in one primary area.

Substantially all of our producing properties and estimated proved reserves are concentrated in Crockett and Schleicher Counties, Texas. As a result of this concentration, we are disproportionately exposed to the natural decline of production from these fields as well as the impact of delays or interruptions of production from these wells caused by significant governmental regulation, transportation capacity constraints, curtailments of production, service delays, natural disasters or other events that impact this area.

Because of our geographic concentration, our purchaser base is limited, and the loss of one of our key purchasers or their inability to take our oil, NGLs or gas could adversely affect our financial results.

In 2017, AMID and DCP collectively accounted for 99% of our total oil, NGLs and gas sales, excluding realized commodity derivative settlements. As of December 31, 2017, we had dedicated the majority of our oil production from northern Project Pangea and Pangea West through September 2022 to AMID. In addition, as of December 31, 2017, we had dedicated the majority of our NGLs and natural gas production from Project Pangea to DCP through August 2023. To the extent that any of our major purchasers reduces their purchases of oil, NGLs or gas, is unable to take our oil, NGLs or gas due to infrastructure or capacity limitations or defaults on their obligations to us, we would be adversely affected unless we were able to make comparably favorable arrangements with other purchasers. These purchasers' default or non-performance could be caused by factors beyond our control. A default could occur as a result of circumstances relating directly to one or more of these customers or due to circumstances related to other market participants with which the customer has a direct or indirect relationship.

We depend on our management team and other key personnel. The loss of any of these individuals, or the inability to attract, train and retain additional qualified personnel, could adversely affect our business, financial condition and the results of operations and future growth.

Our success largely depends on the skills, experience and efforts of our management team and other key personnel and the ability to attract, train and retain additional qualified personnel. The loss of the services of one or more members of our senior management team or of our other employees with critical skills needed to operate our business could have a negative effect on our business, financial condition, results of operations and future growth. In 2011, we entered into an amended and restated employment agreement with J. Ross Craft, P.E., our Chairman and Chief Executive Officer. In 2014, we entered into an employment agreement with Sergei Krylov as the Company's Executive Vice President and Chief Financial Officer. In January 2017, we amended our employment agreements with Qingming Yang, our President and Chief Operating Officer; and J. Curtis Henderson, our Chief Administrative Officer. If any of these officers or other key personnel resign or become unable to continue in their present roles and are not adequately replaced, our business operations could be materially adversely affected. In addition, our ability to manage our growth, if any, will require us to effectively train, motivate and manage our existing employees and to attract, motivate and retain additional qualified personnel. Competition for these types of personnel is intense, and we may not be successful in attracting, assimilating and retaining the personnel required to grow and operate our business profitably.

Market conditions or transportation and infrastructure impediments may hinder our access to oil, NGLs and gas markets or delay our production or sales.

Market conditions or the unavailability of satisfactory oil, NGLs and gas processing and transportation services and infrastructure may hinder our access to oil, NGLs and gas markets or delay our production or sales. Although currently we control the gathering systems for our operations in the Permian Basin, we do not have such control over the regional or downstream pipelines in and out of the Permian Basin. The availability of a ready market for our oil, NGLs and gas production depends on a number of factors, including market demand and the proximity of our reserves to pipelines or trucking and rail terminal facilities.

In addition, the amount of oil, NGLs and gas that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to maintenance, excessive line pressure, excessive vapor pressure, ability of downstream processing facilities to accept unprocessed gas or NGLs, physical damage or operational interruptions to the gathering or transportation system or downstream processing and fractionation facilities or lack of contracted capacity on such systems or facilities.

The curtailments arising from these and similar circumstances may last from a few days to several months, and in many cases, we are provided with limited, if any, notice as to when these circumstances will arise and their duration. As a result, we may not be able to sell, or may have to transport by more expensive means, the oil, NGLs and gas that we produce, or we may be required to shut in oil or gas wells or delay initial production until the necessary gathering and transportation systems are available. Any significant curtailment in gathering systems, transportation, pipeline capacity or significant delay in construction of necessary gathering and transportation facilities, could adversely affect our business, financial condition and results of operations.

Loss of our information and computer systems could adversely affect our business, financial condition and results of operations.

We heavily depend on our information systems and computer-based programs, including drilling, completion and production data, 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 our loss of communication links, inability to find, produce, process and sell oil, NGLs and gas and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. In addition, the U.S. government has issued public warnings that indicate that energy assets might be specific targets of cyber security threats. A cyber incident involving our information systems and related infrastructure could disrupt our business plans and result in information theft, unauthorized access to confidential or otherwise sensitive information, data corruption, operational disruption and/or financial loss. Any such consequence could have a material adverse effect on our business, financial condition and results of operations. In addition, the Company's implementation of various procedures and controls to monitor and mitigate security threats and to increase security for the Company's information, facilities and infrastructure may result in increased capital and operating costs. Costs for insurance may also increase as a result of security threats, and some insurance coverage may become more difficult to obtain, if available at all. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring.

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

We operate in a highly competitive environment for acquiring prospects and productive properties, marketing oil and gas and securing equipment and skilled personnel. Many of our competitors are major and large independent oil and gas companies that have financial, technical and personnel resources substantially greater than ours. Those companies may be able to develop and acquire more prospects and productive properties than our financial or personnel resources permit. Our ability to develop and operate our current project, acquire additional prospects and discover reserves in the future will depend on our ability to hire and retain qualified personnel, evaluate and select suitable properties and consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and gas industry. Larger competitors may be better able to withstand sustained periods of low commodity prices and unsuccessful drilling and absorb the burden of changes in laws and regulations more easily than we can, which would adversely affect our competitive position. We may not be able to compete successfully in the future in attracting and retaining qualified personnel, acquiring prospective reserves, developing reserves, marketing oil, NGLs and gas and raising additional capital.

Our identified drilling locations are scheduled to be drilled over many years, making them susceptible to uncertainties that could prevent them from being drilled or delay their drilling. In certain instances, this could prevent drilling and production before the expiration date of leases for such locations.

Our management team has identified drilling locations as an estimation of our future development activities on our existing acreage. These identified drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these identified drilling locations depends on a number of uncertainties, including oil, NGLs and gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system, marketing and transportation constraints, regulatory approvals and other factors. Because of these uncertain factors, we do not know if the identified drilling locations will ever be drilled or if we will be able to produce oil or gas from these or any other identified drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the identified locations are obtained, the leases for such acreage will expire. Therefore, our actual drilling activities may materially differ from those presently identified.

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The use of geoscientific, petrophysical and engineering analyses and other technical or operating data to evaluate drilling prospects is uncertain and does not guarantee drilling success or recovery of economically producible reserves.

Our decisions to explore, develop and acquire prospects or properties targeting Wolfcamp and other zones in the Permian Basin and other areas depend on data obtained through geoscientific, petrophysical and engineering analyses, the results of which can be uncertain. Even when properly used and interpreted, data from whole cores, regional well log analyses, 3-D seismic and micro-seismic only assist our technical team in identifying hydrocarbon indicators and subsurface structures and estimating hydrocarbons in place. They do not allow us to know conclusively the amount of hydrocarbons in place and if those hydrocarbons are producible economically. In addition, the use of advanced drilling and completion technologies for our Wolfcamp development, such as horizontal drilling and multi-stage fracture stimulations, requires greater expenditures than our traditional development drilling strategies. Our ability to commercially recover and produce the hydrocarbons that we believe are in place and attributable to the Wolfcamp and other zones will depend on the effective use of advanced drilling and completion techniques, the scope of our development project (which will be directly affected by the availability of capital), drilling and production costs, availability of drilling and completion services and equipment, drilling results, lease expirations, regulatory approval and geological and mechanical factors affecting recovery rates. Our estimates of unproved reserves, estimated ultimate recoveries per well, hydrocarbons in place and resource potential may change significantly as development of our oil and gas assets provides additional data.

Unless we replace our oil and gas reserves, our reserves and production will decline.

Our future oil and gas production depends on our success in finding or acquiring additional reserves. If we fail to replace reserves through drilling or acquisitions, our production, revenues and cash flows will be adversely affected. In general, production from oil and gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our total proved reserves will decline as reserves are produced, unless we conduct other successful exploration and development activities or acquire properties containing proved reserves, or both. Our ability to make the necessary capital investment to maintain or expand our asset base of oil and gas reserves would be limited to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. We may not be successful in exploring for, developing or acquiring additional reserves.

We have leases for undeveloped acreage that may expire in the near future.

As of December 31, 2017, we held mineral leases in each of our areas of operation that are still within their original lease term and are not currently held by production. Leases not held by production represent 42% of our net acreage, and 2% of our proved undeveloped reserves. Unless we continue to develop and produce on the properties subject to these leases, these leases may expire in 2018. If these leases expire, we will lose our right to develop the related properties, unless we renew such leases. In addition, many of our leases may be terminated if we fail to meet our continuous development obligations thereunder. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. See Item 2. “Properties — Undeveloped Acreage Expirations” for a table summarizing the expiration schedule of our undeveloped acreage expiring based on contractual lease maturities over the next three years.

Our actual production, revenues and expenditures related to our reserves are likely to differ from our estimates of our proved reserves. We may experience production that is less than estimated and drilling costs that are greater than estimated in our reserve reports. These differences may be material.

The proved oil, NGLs and gas reserves data included in this report are estimates. Petroleum engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. Estimates of economically recoverable oil, NGLs and gas reserves and of future net cash flows necessarily depend upon a number of variable factors and assumptions, including:

- historical production from the area compared with production from other similar producing areas;
- the assumed effects of regulations by governmental agencies;

- assumptions concerning future oil, NGLs and gas prices; and
- assumptions concerning future operating costs, severance and excise taxes, development costs and workover and remedial costs.

Because all reserves estimates are to some degree subjective, each of the following items may differ materially from those assumed in estimating proved reserves:

- the quantities of oil, NGLs and gas that are ultimately recovered;
- the production and operating costs incurred;
- the amount and timing of future development expenditures; and
- future oil, NGLs and gas prices.

As of December 31, 2017, approximately 63% of our proved reserves were proved undeveloped. Estimates of proved undeveloped reserves are even less reliable than estimates of proved developed reserves. Furthermore, different reserve engineers may make different estimates of reserves and future net revenues based on the same available data. Our actual production, revenues and expenditures with respect to reserves will likely be different from estimates and the differences may be material.

We may be unable to make attractive acquisitions or successfully integrate acquired businesses, and any inability to do so may disrupt our business and hinder our ability to grow.

In the future, we may make acquisitions of businesses that complement or expand our current business. We may not be able to identify attractive acquisition opportunities. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms. Competition for acquisitions may also increase the cost of, or cause us to refrain from, completing acquisitions.

The success of any completed acquisition will depend on our ability to integrate effectively the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. No assurance can be given that we will be able to identify suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to integrate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations.

Severe weather could have a material adverse impact on our business.

Our business could be materially and adversely affected by severe weather. For example, our production volumes for the three months ended September 30, 2017, were adversely impacted by Hurricane Harvey, as the main purchaser of our NGLs and natural gas had to temporarily shut in or curtail receipt of NGLs and natural gas at multiple processing plants in the Permian Basin. Additional repercussions of severe weather conditions may include:

- curtailment of services, including oil, NGLs and gas pipelines, processing plants and trucking services;
- weather-related damage to drilling rigs, resulting in a temporary suspension of operations;
- weather-related damage to our producing wells or facilities;
- inability to deliver materials to jobsites in accordance with contract schedules; and
- loss of production.

Operating hazards or other interruptions of our operations could result in potential liabilities, which may not be fully covered by our insurance.

The oil and gas business involves certain operating hazards such as well blowouts, cratering, explosions, uncontrollable flows of gas, oil or well fluids, fires, surface and subsurface pollution and contamination, and releases of toxic gas. The occurrence of one of the above may result in injury, loss of life, suspension of operations, environmental damage and remediation and/or governmental investigations and penalties. Consistent with insurance coverage generally available to the industry, our insurance policies provide limited coverage for losses or liabilities relating to pollution, with broader coverage for sudden and accidental occurrences. Our insurance might be inadequate to cover our liabilities. The insurance market, in general, and the energy insurance market, in particular, have been difficult markets over the past several years. Insurance costs are expected to continue to increase over the next few years, and we may decrease coverage and retain more risk to mitigate future cost increases. If we incur substantial liability and the damages are not covered by insurance or are in excess of policy limits, or if we incur liability at a time when we are not able to obtain liability insurance, then our business, results of operations and financial condition could be materially adversely affected.

Our results are subject to quarterly and seasonal fluctuations.

Our quarterly operating results have fluctuated in the past and could be negatively impacted in the future as a result of a number of factors, including seasonal variations in oil, NGLs and gas prices, variations in levels of production and the completion of development projects.

We have renounced any interest in specified business opportunities, and certain members of our board of directors and certain of our stockholders generally have no obligation to offer us those opportunities.

In accordance with Delaware law, we have renounced any interest or expectancy in any business opportunity, transaction or other matter in which our outside directors and certain of our stockholders, each referred to as a Designated Party, participates or desires to participate in, that involves any aspect of the exploration and production business in the oil and gas industry. If any such business opportunity is presented to a Designated Party who also serves as a member of our board of directors, the Designated Party has no obligation to communicate or offer that opportunity to us, and the Designated Party may pursue the opportunity as he sees fit, unless:

- it was presented to the Designated Party solely in that person’s capacity as a director of our Company and with respect to which, at the time of such presentment, no other Designated Party has independently received notice of, or otherwise identified the business opportunity; or
- the opportunity was identified by the Designated Party solely through the disclosure of information by or on behalf of us.

As a result of this renunciation, our outside directors should not be deemed to have breached any fiduciary duty to us if they or their affiliates or associates pursue opportunities as described above and our future competitive position and growth potential could be adversely affected.

ITEM 1B. UNRESOLVED STAFF COMMENTS

The Company has unresolved Staff comments with respect to its Annual Report on Form 10-K for the fiscal year ended December 31, 2016. These comments primarily related to our proved undeveloped reserves under Rule 4-10(a)(31) of Regulation S-X and, in general, request explanations and supporting detail about the scheduling and reporting of our proved undeveloped reserves and conversion of our proved undeveloped reserves to proved developed reserves.

The Company provided timely written responses to the comments received from the Staff. Management believes the written responses have substantially addressed all comments and, in light of the timing of the filing of this report in relation to the receipt of those comments, the Company has incorporated additional disclosure regarding reporting and conversion of our proved undeveloped reserves into this report to prospectively address certain of these comments. The Company believes it has adequately responded to all of the Staff's comments made to date, but we have not been notified that the Staff's review has been completed. The Company cannot ultimately predict the date of resolution of the unresolved comments or the results of the Staff review.

ITEM 2. PROPERTIES

Permian Basin — Project Pangea

Our properties in the Permian Basin are located in Crockett and Schleicher Counties, Texas. We began operations in the Permian Basin through a farm-in agreement for 27,000 net acres in 2004 and have since increased our total acreage position to approximately 165,000 gross (149,000 net) acres as of year-end 2017. At December 31, 2017, we owned interests in approximately 813 gross (801 net) wells, all of which we operate. As of December 31, 2017, we had working and net revenue interests of approximately 98.5% and 76%, respectively, across Project Pangea.

Our acreage position in the Permian Basin is characterized by several commercial hydrocarbon zones, including the Clearfork, Dean, Wolfcamp shale, Canyon Sands, Strawn and Ellenburger zones. When we began drilling our Permian Basin properties in 2004, we targeted the Canyon Sands, Strawn and Ellenburger zones at depths ranging from 7,250 feet to 8,900 feet with vertical wells.

In 2010, we performed a detailed geological and petrophysical evaluation of the Clearfork, Dean and Wolfcamp shale formations above the Canyon Sands, Strawn and Ellenburger, and in 2010, we began drilling horizontal wells targeting the Wolfcamp shale. The Wolfcamp shale is a source rock that we believe has significant potential for hydrocarbons. The Wolfcamp shale is located in the oil-to-wet gas window across our Permian acreage position and is naturally fractured due to its proximity to the Ouachita-Marathon thrust belt and mineralogy, specifically the carbonate and quartz minerals.

The Wolfcamp shale has gross pay thickness of approximately 1,000 to 1,200 feet across our acreage position, which allows for horizontal drilling and stacked horizontal wellbores targeting varied zones that we call “benches.” We believe effectively developing the Wolfcamp shale may involve up to three lateral wellbores, each targeting a different bench, which we refer to as the Wolfcamp A, B and C. Since we began drilling horizontal Wolfcamp wells in 2011 through December 31, 2017, we have drilled and completed a total of 18 wells targeting the Wolfcamp A bench, 110 wells targeting the Wolfcamp B bench and 50 wells targeting the Wolfcamp C bench. As of December 31, 2017, estimated proved reserves attributable to the horizontal Wolfcamp shale oil play accounted for 94% of our total proved reserves.

During 2017, we incurred costs of approximately $44.2 million to drill 13, and complete nine, horizontal Wolfcamp wells. At December 31, 2017, we had 10 horizontal Wolfcamp wells waiting on completion. We have no rigs running in Project Pangea.

East Texas Basin — North Bald Prairie

In 2007, we entered into a joint venture with EnCana Oil & Gas (USA) Inc. (“EnCana”) in Limestone and Robertson Counties, Texas, in the East Texas Cotton Valley trend. We currently have nine gross producing gas wells. We have a 50% working interest and approximately 40% net revenue interest in the approximately 3,000 gross (2,000 net) acre project. In 2012, EnCana assigned its interest in the project to a third party. As of December 31, 2017, we had estimated proved reserves of 856 MMcf in North Bald Prairie. Our primary targets in North Bald Prairie are the Cotton Valley Sands and Cotton Valley Lime. We currently have no rigs running in North Bald Prairie.

Proved Oil and Gas Reserves

The following table sets forth summary information regarding our estimated proved reserves as of December 31, 2017. See Note 10 to our consolidated financial statements in this report for additional information. Our reserve estimates and our calculation of standardized measure and PV-10 are based on the 12-month average of the first-day-of-the-month pricing of $51.34 per Bbl West Texas Intermediate posted oil price, $18.67 per Bbl received for NGLs and $2.99 per MMBtu Henry Hub spot natural gas price during 2017. All prices were adjusted for energy content, quality and basis differentials by area and were held constant through the lives of the properties. Natural gas is converted at a rate of six Mcf of gas to one barrel of oil equivalent (“Boe”). NGLs are converted at a rate of one barrel of NGLs to one Boe. The ratios of six Mcf of gas to one Boe and one barrel of NGLs to one Boe do not assume price equivalency and, given price differentials, the price for a Boe of natural gas or NGLs may differ significantly from the price of a barrel of oil. The information in the following table is not intended to represent the current market value of our proved reserves nor does it give any effect to or reflect our commodity derivatives or current commodity prices.

Summary of Oil and Gas Reserves as of Fiscal-Year End

Based on Average Fiscal-Year Prices

	Proved Reserves					
			Natural			
	Oil	NGLs	Gas	Total	Percent	PV-10
Reserves Category	(MBbls)	(MBbls)	(MMcf)(1)	(MBoe)	(%)	(in millions)(2)
Proved Developed						
Permian Basin	13,853	23,180	175,345	66,256	36.6 %	$ 395.3
East Texas Basin	—	—	856	143	0.0	0.5
Proved Undeveloped						
Permian Basin	36,207	34,768	265,028	115,146	63.4	125.2
Total Proved Reserves	50,060	57,948	441,229	181,545	100.0 %	$ 521.0

(1) The gas reserves contain 57,835 MMcf of gas that will be produced and used as field fuel (primarily for compressors and artificial lifts) before the gas is delivered to a sales point.
(2) See "Reconciliation of PV-10 to Standardized Measure" below for a reconciliation of PV-10 to the standardized measure.

Our estimated total proved reserves of oil, NGLs and natural gas as of December 31, 2017, were 181.5 MMBoe, made up of 28% oil, 32% NGLs and 40% natural gas. The proved developed portion of total proved reserves at year-end 2017 was 37%.

Extensions and discoveries for 2017 were 33.3 MMBoe, primarily attributable to our development project in the Wolfcamp shale oil resource play in the Permian Basin. During 2017, we acquired 1.6 MMBoe of proved reserves through the Bolt-On Acquisition, and we reclassified 17.7 MMBoe of proved undeveloped reserves to unproved reserves. The reserves reclassified are attributable to horizontal well locations in Project Pangea that are no longer expected to be developed within five years from their initial booking, as required by SEC rules. Revisions included an increase of 9.4 MMBoe resulting from updated well performance and technical parameters, and an increase of 3.1 MMBoe due to higher commodity prices. We produced 4.5 MMBoe during 2017. This production included 1,319 MMcf of gas that was produced and used as field fuel (primarily for compressors and artificial lift) before the gas was delivered to a sales point.

Reconciliation of PV-10 to Standardized Measure

PV-10 is our estimate of the present value of future net revenues from proved oil and gas reserves after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates of future income taxes. PV-10 is a non-GAAP, financial measure and generally differs from the standardized measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future cash flows. PV-10 should not be considered as an alternative to the standardized measure as computed under GAAP.

We believe PV-10 to be an important measure for evaluating the relative significance of our oil and gas properties and that the presentation of PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and gas companies. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable for evaluating our company. We believe that most other companies in the oil and gas industry calculate PV-10 on the same basis.

The following table provides a reconciliation of PV-10 to the standardized measure of discounted future net cash flows at December 31, 2017:

	December 31, 2017 (in millions)
PV-10	$ 521.0
Present value of future income tax discounted at 10%	(60.0)
Standardized measure of discounted future net cash flows	$ 461.0

Proved Undeveloped Reserves

As of December 31, 2017, we had 115.1 MMBoe of proved undeveloped ("PUD") reserves, which is an increase of 17.6 MMBoe, or 18%, compared with 97.5 MMBoe of PUD reserves at December 31, 2016. All of our PUD reserves at December 31, 2017, were associated with our core development project, Project Pangea.

The following table summarizes the changes in our PUD reserves during 2017.

	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total (MBoe)
Balance — December 31, 2016	36,565	27,259	202,069	97,502
Extensions and discoveries	10,288	9,922	76,239	32,916
Revisions to previous estimates	(9,282)	(1,123)	(3,950)	(11,064)
Conversion to proved developed reserves	(1,364)	(1,289)	(9,330)	(4,209)
Balance — December 31, 2017	36,207	34,769	265,028	115,145

Extensions and discoveries relating to proved undeveloped reserves for 2017 were 32.9 MMBoe, primarily attributable to our development of Project Pangea in the Wolfcamp shale oil resource play in the Permian Basin. During 2017, we converted 4.2 MMBoe of proved undeveloped reserves to proved developed reserves, and reclassified 17.7 MMBoe of proved undeveloped reserves to unproved reserves. The reserves reclassified are attributable to horizontal well locations in Project Pangea that are no longer expected to be developed within five years from their initial booking, as required by SEC rules. Revisions included the reclassified reserves, with an increase of 5.6 MMBoe resulting from updated well performance and technical parameters and an increase of 1 MMBoe due to higher commodity prices.

The following table sets forth our PUD reserves converted to proved developed reserves during 2017, 2016 and 2015 and the net investment required to convert PUD reserves to proved developed reserves during each year.

	Proved Undeveloped Reserves Converted to Proved Developed Reserves				Investment in Conversion of Proved Undeveloped Reserves to Proved Developed Reserves
Year Ended December 31,	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total (MBoe)	(in thousands)
2015	2,485	1,627	11,737	6,068	$ 84,071
2016	419	433	3,140	1,376	11,008
2017	1,364	1,289	9,330	4,209	35,418
Total	4,268	3,349	24,207	11,653	$ 130,497

In July 2015, we suspended our drilling and completion activities due to the sustained low commodity prices. In 2016, we resumed limited drilling and completion activities as commodity prices remained depressed and

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volatile. The prolonged depression of commodity prices significantly impacted our conversion of PUD reserves to proved developed reserves. However, we expect our conversion of PUD reserves to proved developed reserves to increase due to the reinvestment of our increased operating cash flows into our development plans.

Estimated future development costs relating to the development of PUD reserves are projected to be approximately $55.5 million in 2018, $310.6 million in 2019 and $226.3 million in 2020. We monitor fluctuations in commodity prices, drilling and completion costs, operating expenses and drilling success to determine adjustments to our drilling and development project.

Preparation of Proved Reserves Estimates

Internal Controls Over Preparation of Proved Reserves Estimates

Our policies regarding internal controls over the recording of reserve estimates require reserve estimates to be in compliance with SEC rules, regulations and guidance and prepared in accordance with “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007)” promulgated by the Society of Petroleum Engineers (“SPE standards”). Our proved reserves are estimated at the property level and compiled for reporting purposes by our corporate reservoir engineering staff, all of whom are independent of our operations team. We maintain our internal evaluations of our reserves in a secure reserve engineering database. The corporate reservoir engineering staff interacts with our internal staff of operations engineers and geoscience professionals and with accounting employees to obtain the necessary data for the reserves estimation process. Our internal professional staff works closely with our external engineers to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve estimation process. All of the reserve information maintained in our secure reserve engineering database is provided to the external engineers. In addition, other pertinent data is provided such as seismic information, geologic maps, well logs, production tests, material balance calculations, well performance data, operating procedures and relevant economic criteria. We make available all information requested, including our pertinent personnel, to the external engineers as part of their evaluation of our reserves.

Our Senior Vice President of Engineering, Troy Hoefer, is the individual responsible for overseeing the preparation of our reserve estimates and for internal compliance of our reserve estimates with SEC rules, regulations and SPE standards. Mr. Hoefer has a Bachelor of Science degree in Petroleum Engineering from the Colorado School of Mines and more than 25 years of industry experience. Mr. Hoefer reports to our President and Chief Operating Officer. Our executive management, including our Chief Executive Officer and our President and Chief Operating Officer, reviews and approves our reserves estimates, including future development costs, before these estimates are finalized and disclosed in a public filing or presentation. Our Chief Executive Officer, J. Ross Craft, P.E., is a licensed Professional Engineer with a Bachelor of Science Degree in Petroleum Engineering from Texas A&M University and more than 30 years of industry experience. Our President and Chief Operating Officer, Qingming Yang, earned his B.S. in Petroleum Geology from Chengdu University of Technology in the People’s Republic of China, his M.A. in Geology from George Washington University and his Ph.D. in Structural Geology from the University of Texas at Dallas. Dr. Yang has more than 25 years of industry experience.

For the years ended December 31, 2017, 2016 and 2015, we engaged DeGolyer and MacNaughton, independent petroleum engineers, to prepare independent estimates of the extent and value of the proved reserves associated with certain of our oil and gas properties. In 2017, DeGolyer and MacNaughton reported to the Audit Committee of our Board of Directors and to our Senior Vice President of Engineering. The Audit Committee meets with the independent engineering firm to, among other things, review and consider the processes used by the engineers in the preparation of the report and any matters of importance that arose in the preparation of the report, including whether the independent engineering firm encountered any material problems or difficulties in the preparation of their report. The Audit Committee's review specifically includes difficulties with the scope or timeliness of the information furnished to them by the Company or any restrictions on access to information placed upon them by any Company personnel, any other difficulties in dealing with any Company personnel in the preparation of the report and any other matters of concern relating to the preparation of the report. The Audit Committee also determines whether the Company or its management or senior engineering personnel had similar or other problems or concerns regarding the independent engineering firm and the preparation of their report. See Third-Party Reports below for further information regarding DeGolyer and MacNaughton's report.

Technologies Used in Preparation of Proved Reserves Estimates

Estimates of reserves were prepared in compliance with SEC rules, regulations and guidance and SPE standards. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data and production history. For our properties, structure and isopach maps were constructed to delineate each reservoir. Electrical logs, radioactivity logs, seismic data and other available data were used to prepare these maps. Parameters of area, porosity and water saturation were estimated and applied to the isopach maps to obtain estimates of original oil in place or original gas in place. For developed producing wells whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were determined using decline curve analysis. Reserves for producing wells whose performance was not yet established and for undeveloped locations were estimated using type curves. The parameters needed to develop these type curves such as initial decline rate, "b" factor and final decline rate were based on nearby wells producing from the same reservoir and with a similar completion for which more data were available.

Reporting of NGLs

We produce NGLs as part of the processing of our natural gas. The extraction of NGLs in the processing of natural gas reduces the volume of natural gas available for sale. At December 31, 2017, NGLs represented approximately 32% of our total proved reserves on a Boe basis. NGLs are products sold by the gallon. In reporting proved reserves and production of NGLs, we include these volumes and production as Boe. The prices we received for a standard barrel of NGLs in 2017 averaged approximately 61% lower than the average prices for equivalent volumes of oil. We report all production information related to natural gas net of the effect of any reduction in natural gas volumes resulting from the processing of NGLs.

Third-Party Reports

For the years ended December 31, 2017, 2016 and 2015, we engaged DeGolyer and MacNaughton, independent petroleum engineers, to prepare estimates of the extent and value of the proved reserves of certain of our oil and gas properties, including 100% of our total reported proved reserves. DeGolyer and MacNaughton's report for 2017 is included as Exhibit 99.1 to this annual report on Form 10-K.

Oil and Gas Production, Production Prices and Production Costs

The following table sets forth summary information regarding oil, NGLs and gas production, average sales prices and average production costs for the last three years. We determined the Boe using the ratio of six Mcf of natural gas to one Boe, and one barrel of NGLs to one Boe. The ratios of six Mcf of natural gas to one Boe and one barrel of NGLs to one Boe do not assume price equivalency and, given price differentials, the price for a Boe for natural gas or NGLs may differ significantly from the price for a barrel of oil.

	Years Ended December 31,		
Production	2017	2016	2015
Oil (MBbls)	1,107	1,275	1,882
NGLs (MBbls)	1,486	1,529	1,694
Gas (MMcf)(1)	9,829	10,404	11,732
Total (MBoe)	4,232	4,537	5,532
Total (MBoe/d)	11.6	12.4	15.2
Average prices			

Oil (per Bbl)	$47.63	$37.90	$43.65
NGLs (per Bbl)	18.64	12.93	12.06
Gas (per Mcf)	2.53	2.14	2.45
Total (per Boe)	24.89	19.90	23.74
Net cash (payment) receipt on derivative settlements (per Boe)	(1.03)	1.35	9.49
Total including derivative impact (per Boe)	$23.86	$21.25	$33.23
Production costs (per Boe)(2)	$4.23	$4.24	$5.24

(1) Gas production excludes gas produced and used as field fuel (primarily for compressors and artificial lifts) before the gas was delivered to a sales point.

(2) Production cost per Boe represents lease operating expenses and excludes production and ad valorem taxes.
Drilling Activity — Prior Three Years

The following table sets forth information on our drilling activity for the last three years. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value.

	Years Ended December 31,					
	2017		2016		2015	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	13.0	12.9	6.0	6.0	20.0	20.0
Dry(1)	—	—	—	—	1.0	1.0
Exploratory wells:						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total wells:						
Productive	13.0	12.9	6.0	6.0	20.0	20.0
Dry	—	—	—	—	1.0	1.0

(1) The Company encountered mechanical issues while drilling the wells classified as dry in 2015.
In 2017, we drilled 13 horizontal wells and completed nine horizontal wells. At December 31, 2017, 10 wells were waiting on completion. The Company encountered mechanical issues while drilling one well in 2015 and this well cost $2.4 million.

Although a well may be classified as productive upon completion, future changes in oil, NGLs and gas prices, operating costs and production may result in the well becoming uneconomical.

Drilling Activity — Current

As of the date of this report, we had no rigs operating.

Delivery Commitments

We are not committed to provide a fixed and determinable quantity of oil, NGLs or gas under existing agreements. However, as of December 31, 2017, we had dedicated the majority of our oil production from northern Project Pangea and Pangea West through September 2022 to AMID and had dedicated the majority of our NGLs and natural gas production from Project Pangea to DCP through August 2023.

Producing Wells

The following table sets forth the number of producing wells in which we owned a working interest at December 31, 2017. Wells are classified as natural gas or oil according to their predominant production stream.

	Natural Gas Wells		Oil Wells		Total Wells		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Permian Basin	550	539	263	262	813	801	98.5 %
East Texas Basin	9	4.5	—	—	9	4.5	49.9 %
Total	559	543.5	263	262	822	805.5	97.9 %

Acreage

The following table summarizes our developed and undeveloped acreage as of December 31, 2017.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Permian Basin	95,009	86,433	69,685	62,874	164,694	149,307
East Texas Basin	3,481	1,687	—	—	3,481	1,687
Total	98,490	88,120	69,685	62,874	168,175	150,994

The undeveloped acreage includes 58,565 net acres subject to continuous development obligations, and these leases may be terminated if we fail to meet our continuous development obligations. The net undeveloped acres subject to continuous development obligations includes 35,867 net acres acquired in the Bolt-On Acquisition and 16,533 net acres leased from The Board for Lease of University Lands ("University Lands") under a Drilling and Development Unit Agreement ("D&D agreement"). We are required to drill one well approximately every six months on the undeveloped acreage acquired in the Bolt-On Acquisition. Under the D&D agreement, we are required to drill and complete two wells per calendar year, and in September 2018, we will present a development plan to University Lands that will outline a proposed capital budget and drilling schedule for the following year. Upon approval of the plan of development by University Lands (not to be unreasonably withheld), the development plan will become the drilling obligation for the following year.

Undeveloped Acreage Expirations

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2017, which will expire over the next three years by project area, based on contractual lease maturities, unless production is established before lease expiration dates. Net amounts may be greater than gross amounts in a particular year due to timing of expirations.

	2018		2019		2020	
	Gross	Net	Gross	Net	Gross	Net
Permian Basin	107	2,453	1,920	467	—	—
East Texas Basin	—	—	—	—	—	—
Total	107	2,453	1,920	467	—	—

The expiring acreage set forth in the table above accounts for 2% of our net acreage, and 2% of our PUD reserves. We are generally engaged in a combination of drilling and development and discussions with mineral lessors for lease extensions and renewals to address the expiration of undeveloped acreage that occurs in the normal course of our business.

ITEM 3. LEGAL PROCEEDINGS

We are involved in various legal and regulatory proceedings arising in the normal course of business. While we cannot predict the outcome of these proceedings with certainty, we do not believe that an adverse result in any pending legal or regulatory proceeding, individually or in the aggregate, would be material to our business, financial condition and results of operations.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Market Information

Our common stock is traded on NASDAQ Global Select Market in the United States under the symbol "AREX." During 2017, trading volume averaged 757,621 shares per day. The following table shows the quarterly high and low sale prices of our common stock as reported on NASDAQ for the past two years.

	Price Per Share	
	High	Low
2017		
First quarter	$3.70	$1.93
Second quarter	3.41	1.95
Third quarter	3.56	2.23
Fourth quarter	3.13	2.19
2016		
First quarter	$2.05	$0.60
Second quarter	3.10	1.13
Third quarter	4.35	1.35
Fourth quarter	4.33	2.51

Holders

As of February 20, 2018, there were 162 record holders of our common stock. A record holder may be a broker or other entity holding shares in street name for one or more customers who beneficially own the shares.

Dividends

We have not paid any cash dividends on our common stock. We do not expect to pay any cash or other dividends in the foreseeable future on our common stock, as we intend to reinvest cash flow generated by operations into our business. Our revolving credit facility currently restricts our ability to pay cash dividends on our common stock, and we may also enter into credit agreements or other borrowing arrangements in the future that restrict or limit our ability to pay cash dividends on our common stock.

Securities Authorized for Issuance under Equity Compensation Plans

The following table sets forth information regarding securities authorized for issuance under equity compensation plans and individual compensation arrangements as of December 31, 2017.

Plan Category	Number of	Weighted-Average	Number of Securities

	Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)	Exercise Price of Outstanding Options, Warrants and Rights (b)	Remaining Available for Future Issuance under Equity Compensation Plans (Excluding Securities Reflected in Column (a))(1) (c)
Equity compensation plans approved by stockholders	—	$ —	527,125
Equity compensation plans not approved by stockholders	—	—	—

Performance Graph

The following graph compares the cumulative return on a $100 investment in our common stock from December 31, 2012, through December 31, 2017, to that of the cumulative return on a $100 investment in the Standard & Poor's 500 ("S&P 500") index, and Standard & Poor's 600 Small Cap Energy index for the same period. In calculating the cumulative return, reinvestment of dividends, if any, is assumed. This graph is not "soliciting material," is not deemed filed with the SEC and is not to be incorporated by reference in any of our filings under the Securities Act or the Exchange Act, whether made before or after the date hereof and irrespective of any general incorporation language in any such filing. This graph is included in accordance with the SEC's disclosure rules. This historic stock performance is not indicative of future stock performance.

COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL RETURN

Among Approach Resources Inc., the S&P 500 Index and the S&P 600 Small Cap Energy Index

	12/31/2012	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017
Approach Resources Inc.	$ 100.00	$ 77.17	$ 25.55	$ 7.36	$ 13.39	$ 11.84
S&P 500	100.00	129.60	144.36	143.31	156.98	187.47
S&P 600 Small Cap Energy Index	100.00	137.80	88.64	46.42	63.85	46.81

Issuer Repurchases of Equity Securities

Our 2007 Stock Incentive Plan (the “2007 Plan”) allows us to withhold shares of common stock to pay withholding taxes payable upon vesting of a restricted stock grant. The following table shows the number of shares of common stock withheld to satisfy the income tax withholding obligations arising upon the vesting of restricted shares issued to employees under the 2007 Plan.

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
October 1, 2017 — October 31, 2017	29,979	$ 2.52	—	—
November 1, 2017 — November 30, 2017	2,027	2.44	—	—
December 1, 2017 — December 31, 2017	165,671	2.73	—	—
Total	197,677	$ 2.70	—	—

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth selected financial information for the five years ended December 31, 2017. This information should be read in conjunction with Item 7 of this report, "Management's Discussion and Analysis of Financial Condition and Results of Operations," and our consolidated financial statements, related notes and other financial information included in this report.

	Years Ended December 31,				
	2017	2016	2015	2014	2013
	(in thousands, except per-share data)				
Operating Results Data					
Revenues					
Oil, NGLs and gas sales	$105,349	$90,302	$131,336	$258,529	$181,302
Expenses					
Lease operating	17,902	19,250	28,972	32,701	19,152
Production and ad valorem taxes	8,644	8,217	11,085	15,934	12,840
Exploration	3,657	3,923	4,439	3,831	2,238
Impairment of oil and gas properties	—	—	220,197	—	—
General and administrative	24,333	24,734	28,341	32,104	26,524
Termination costs	—	—	1,436	—	—
Depletion, depreciation and amortization	70,521	79,044	109,319	106,802	76,956
Total expenses	125,057	135,168	403,789	191,372	137,710
Operating (loss) income	(19,708)	(44,866)	(272,453)	67,157	43,592
Other					
Interest expense, net	(21,053)	(27,259)	(25,066)	(21,651)	(14,084)
Gain on debt extinguishment	5,053	—	10,563	—	—
Write-off of debt issuance costs	—	(563)	—	—	—
Equity in (losses) earnings of investee	—	—	—	(181)	156
Gain on sale of equity method investment	—	—	—	—	90,743
Commodity derivative (loss) gain	(262)	(5,484)	19,275	44,472	(5,644)
Other income	32	1,511	172	67	—
(Loss) Income before provision for income tax provision (benefit)	(35,938)	(76,661)	(267,509)	89,864	114,763
Income tax provision (benefit)	76,421	(24,418)	(93,405)	33,692	42,507
Net (loss) income	$(112,359)	$(52,243)	$(174,104)	$56,172	$72,256
(Loss) Earnings per share					
Basic	$(1.35)	$(1.26)	$(4.30)	$1.43	$1.85
Diluted	$(1.35)	$(1.26)	$(4.30)	$1.42	$1.85
Statement of Cash Flows Data					
Net cash provided by (used in)					
Operating activities	$37,454	$26,081	$102,716	$171,604	$110,695
Investing activities	(52,409)	(23,890)	(217,347)	(377,172)	(187,324)
Financing activities	14,955	(2,770)	114,799	147,239	134,623
Balance Sheet Data					
Cash and cash equivalents	$21	$21	$600	$432	$58,761
Restricted cash	—	—	—	—	7,350
Other current assets	16,679	12,473	19,838	60,647	24,302

Property, equipment, net, successful efforts method, net	1,082,876	1,092,061	1,154,546	1,331,659	1,047,030
Other assets	—	—	—	—	1,388
Total assets	$1,099,576	$1,104,555	$1,174,984	$1,392,738	$1,138,831
Current liabilities	$25,067	$26,369	$28,508	$106,852	$84,441
Long-term debt, net	373,460	498,349	496,587	391,311	243,347
Other long-term liabilities	93,633	16,885	41,922	120,248	100,548
Stockholders’ equity	607,416	562,952	607,967	774,327	710,495
Total liabilities and stockholders’ equity	$1,099,576	$1,104,555	$1,174,984	$1,392,738	$1,138,831

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

The following discussion is intended to assist in understanding our results of operations and our financial condition. Our consolidated financial statements and the accompanying notes included elsewhere in this report contain additional information that should be referred to when reviewing this material. Statements in this discussion may be forward-looking. These forward-looking statements involve risks and uncertainties, which could cause actual results to differ from those expressed. See "Cautionary Statement Regarding Forward-Looking Statements" at the beginning of this report and "Risk Factors" in Item 1A. for additional discussion of some of these factors and risks.

Overview

Approach Resources Inc. is an independent energy company focused on the exploration, development, production and acquisition of unconventional oil and gas reserves in the Midland Basin of the greater Permian Basin in West Texas, where we lease approximately 149,000 net acres as of December 31, 2017. We believe our concentrated acreage position and extensive, integrated field infrastructure system provides us an opportunity to achieve cost, operating and recovery efficiencies in the development of our drilling inventory. Our long-term business strategy is to develop resource potential from the Wolfcamp shale oil formation and pursue acquisitions that meet our strategic and financial objectives. See "Item 1 — Business — Our Business Strategy". Additional drilling targets could include the Clearfork, Canyon Sands, Strawn and Ellenburger zones. We sometimes refer to our development project in the Permian Basin as "Project Pangea," which includes "Pangea West." Our management and technical team have a proven track record of finding and developing reserves through advanced drilling and completion techniques. As the operator of all of our estimated proved reserves and production, we have a high degree of control over capital expenditures and other operating matters.

At December 31, 2017, our estimated proved reserves were 181.5 million barrels of oil equivalent ("MMBoe"). Substantially all of our proved reserves are located in Crockett and Schleicher Counties, Texas. The following are important characteristics of our proved reserves at December 31, 2017:

- 28% oil, 32% NGLs and 40% natural gas;
- 37% proved developed;
- 100% operated;
- Reserve life of approximately 43 years based on 2017 production of 4.2 MMBoe;
- Standardized measure of discounted future net cash flows ("standardized measure") of $461 million; and
- PV-10 (non-GAAP) of $521 million.

PV-10 is our estimate of the present value of future net revenues from proved oil, NGLs and natural gas reserves after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates for future income taxes. Estimated future net revenues are discounted at an annual rate of 10% to determine their present value. PV-10 is a financial measure that is not determined in accordance with accounting principles generally accepted in the United States ("GAAP"), and generally differs from the standardized measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future cash flows. PV-10 should not be considered as an alternative to the standardized measure, as computed under GAAP. See Item 2. "Properties — Proved Oil and Gas Reserves" for a reconciliation of PV-10 to the standardized measure.

At December 31, 2017, we owned and operated 813 producing oil and gas wells in the Permian Basin. During 2017, we produced 4.2 MMBoe, or 11.6 MBoe/d. Production for 2017 was 26% oil, 35% NGLs and 39% natural gas.

Our financial results depend on many factors, but particularly on the price of oil, NGLs and gas. Commodity prices are affected by changes in market demand, which is impacted by factors outside of our control, including

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domestic and foreign supply of oil, NGLs and gas, overall domestic and global economic conditions, commodity processing, gathering and transportation availability and the availability of refining capacity, price and availability of alternative fuels, price and quantity of foreign imports, domestic and foreign governmental regulations, political conditions in or affecting other oil and gas producing countries, weather and technological advances affecting oil, NGLs and gas consumption. As a result, we cannot accurately predict future oil, NGLs and gas prices, and therefore, we cannot determine what effect increases or decreases will have on our capital program, production volumes and future revenues. For example, in 2017, NYMEX-WTI oil prices ranged from a high of $60.42 per Bbl to a low of $42.53 per Bbl, NYMEX-Henry Hub natural gas prices ranged from a high of $3.72 per MMBtu to a low of $2.56 per MMBtu, and our realized prices for NGLs ranged from a high of $23.55 per Bbl to a low of $14.95 per Bbl. If the current oil or natural gas prices decline from current levels, they could have a material adverse effect on our business, financial condition and results of operations and quantities of oil, natural gas and NGLs reserves that may be economically produced and liquidity that may be accessed through our borrowing base under our revolving credit facility and through capital markets.

We also face the challenge of financing exploration, development and future acquisitions. We believe we have adequate liquidity for current, near-term working capital needs from cash generated from operations and, to the extent available, unused borrowing capacity under our revolving credit facility. However, we may choose to issue new equity, long-term debt or other convertible debt or equity securities in the capital markets, depending on market conditions and availability, to address our near-term funding requirements, or as an alternative to borrowing under our revolving credit facility. In the longer term, the Company expects a portion of its funding needs to be covered by cash flows from operations, and may issue debt or equity or monetize assets to cover any difference between cash flow from operations and capital or liquidity needs. We cannot guarantee that such financing will be available on acceptable terms or at all.

In addition to production volumes, financing and commodity prices, finding and developing sufficient amounts of oil and gas reserves at economical costs is critical to our long-term success. Future finding and development costs are subject to changes in the industry, including the costs of acquiring, drilling and completing our projects. We focus our efforts on increasing oil and gas reserves and production while controlling costs at a level that is appropriate for long-term operations. Our future cash flow from operations will depend on our ability to manage our overall cost structure.

Like all oil and gas production companies, we face the challenge of natural production declines. Oil and gas production from a given well naturally decreases over time. Additionally, our wells have a rapid initial production decline. We attempt to overcome this natural decline by drilling to develop and identify additional reserves, farm-ins or other joint drilling ventures and by acquisitions. However, during times of severe price declines, we may reduce current capital expenditures and curtail drilling operations in order to preserve liquidity. A material reduction in capital expenditures and drilling activities could materially reduce our production volumes and revenues.

2017 Activity

Our 2017 activity focused on increasing our capital expenditures in a disciplined manner in connection with slowly recovering commodity prices, strengthening our balance sheet and increasing our operating cash flow. We drilled 13, and completed nine, horizontal wells in 2017 in the Wolfcamp shale oil resource play in the Midland Basin. We plan to continue to develop the Wolfcamp shale in Project Pangea in 2018, at a measured pace subject to commodity prices. Our activities in 2017 included:

- Managed production decline and positioned to resume production growth. In response to depressed and volatile commodity prices, we substantially reduced our drilling activity beginning in 2015 and throughout 2016, which led to a natural decline in production. In the first quarter of 2017, our production averaged 11.4 MBoe/d. Throughout

2017, we increased the pace of our drilling activity, and our production averaged 11.7 MBoe/d for the remainder of the year. Production for 2017 totaled 4.2 MMBoe (11.6 MBoe/d), compared to 4.5 MMBoe (12.4 MBoe/d) in 2016. Production for 2017 was 26% oil, 35% NGLs and 39% natural gas. At December 31, 2017, 10 wells were waiting on completion.

- Strengthened our balance sheet and preserved financial flexibility. In November 2016, we entered into an exchange agreement (the "Exchange Agreement") with the largest holder of our 7% Senior Notes due

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2021 (the “Senior Notes”) under which we exchanged $130,552,000 principal amount of our Senior Notes for 39,165,600 newly issued shares of our common stock (the “Initial Exchange”). In March 2017, we exchanged an additional $14,528,000 principal amount of outstanding Senior Notes for 4,009,728 shares of our common stock (the “Follow-On Exchange”). The Initial Exchange and the Follow-On Exchange (together, the “Exchange Transactions”) reduced interest payments by $44.3 million over the remaining term of the Senior Notes, which allowed us to increase our capital budget out of operating cash flow. Additionally, in December 2017, we extended the term on our revolving credit facility by one year to May 7, 2020, and reaffirmed our $325 million borrowing base.

- Increased operating cash flow. In 2017, improved commodity prices and the Exchange Transactions resulted in an increase in operating cash flow by $11.4 million or 44%, which was used to fund our expanded drilling program in 2017. Additionally, in November 2017, we acquired, through an issuance of our common stock, producing Wolfcamp shale assets adjacent to our Project Pangea acreage (the “Bolt-On Acquisition”). The Bolt-On Acquisition included estimated proved developed reserves of 1.6 MMboe, and is expected to increase our operating cash flow and production.
- Delineation of the multi-zone potential of the Wolfcamp shale. The Wolfcamp shale has a gross pay thickness of approximately 1,000 to 1,200 feet, which allows for stacked wellbores targeting three different zones that we call “benches.” We believe effectively developing the Wolfcamp shale may involve up to three lateral wellbores, each targeting a different bench, which we refer to as the Wolfcamp A, B and C. As of December 31, 2017, we had drilled and completed a total of 18 wells targeting the Wolfcamp A bench, 110 wells targeting the Wolfcamp B bench and 50 wells targeting the Wolfcamp C bench. We have successful wells targeting each of the Wolfcamp benches, and we continued development of the Wolfcamp shale in 2017.
- Installation of field infrastructure and water handling systems. Our large, mostly contiguous acreage position and our success in the Wolfcamp shale oil play led us to invest over $120 million in building field infrastructure since 2012. We now have an extensive network of centralized production facilities, water transportation, handling and recycling systems, gas lift lines and salt water disposal wells. In addition, we believe the infrastructure reduces the need for trucks, reduces fresh water usage, improves drilling and completion efficiencies and drives down drilling and completion and operating costs. We were able to reduce our lease operating expenses by 7%, or $1.3 million, in 2017 partially due to this infrastructure investment.

Plans for 2018

For 2018, we increased our capital expenditure budget to a range of $50 million to $70 million, compared to $47.1 million of capital expenditures in 2017. We plan to operate one rig on an intermittent basis during the year in Project Pangea. Our 2018 capital budget excludes acquisitions and lease extensions and renewals and is subject to change depending upon a number of factors, including prevailing and anticipated prices for oil, NGLs and gas, results of horizontal drilling and completions, economic and industry conditions at the time of drilling, the availability of sufficient capital resources for drilling prospects, our financial results and the availability of lease extensions and renewals on reasonable terms. Although the impact of changes in these collective factors in the current commodity price environment is difficult to estimate, we currently expect to execute our development plan based on current conditions. To the extent there is a significant increase or decrease in commodity prices in the future, we will assess the impact on our development plan at that time, and we may respond to such changes by altering our capital budget or our development plan.

Results of Operations

The following table sets forth summary information regarding oil, NGLs and gas revenues, production, average product prices and average production costs and expenses for the last three years. We determined the Boe using the ratio of six Mcf of natural gas to one Boe, and one barrel of NGLs to one Boe. The ratios of six Mcf of natural gas to one Boe and one barrel of NGLs to one Boe do not assume price equivalency and, given price differentials, the price for a Boe for natural gas or NGLs may differ significantly from the price for a barrel of oil.

	Years Ended December 31,		
	2017	2016	2015
Revenues (in thousands)			
Oil	$52,748	$48,311	$82,170
NGLs	27,702	19,761	20,437
Gas	24,899	22,230	28,729
Total oil, NGLs and gas sales	105,349	90,302	131,336
Net cash (payment) receipt on derivative settlements	(4,359)	6,132	52,489
Total oil, NGLs and gas sales including derivative impact	$100,990	$96,434	$183,825
Production			
Oil (MBbls)	1,107	1,275	1,882
NGLs (MBbls)	1,486	1,529	1,694
Gas (MMcf)	9,829	10,404	11,732
Total (MBoe)	4,232	4,537	5,532
Total (MBoe/d)	11.6	12.4	15.2
Average prices			
Oil (per Bbl)	$47.63	$37.90	$43.65
NGLs (per Bbl)	18.64	12.93	12.06
Gas (per Mcf)	2.53	2.14	2.45
Total (per Boe)	$24.89	$19.90	$23.74
Net cash (payment) receipt on derivative settlements (per Boe)	(1.03)	1.35	9.49
Total including derivative impact (per Boe)	$23.86	$21.25	$33.23
Costs and expenses (per Boe)			
Lease operating	$4.23	$4.24	$5.24
Production and ad valorem taxes	2.04	1.81	2.00
Exploration	0.86	0.86	0.80
General and administrative	5.75	5.45	5.12
Depletion, depreciation and amortization	16.66	17.42	19.76

Oil, NGLs and gas sales. Oil, NGLs and gas sales for 2017 increased $15 million, or 17%, to $105.3 million from $90.3 million in 2016. The increase in oil, NGLs and gas sales was due to an increase in average realized commodity prices ($21.1 million), partially offset by a decrease in production volumes ($6.1 million). In 2017, the average price we received for our production, before the effect of commodity derivatives, increased 25% to $24.89 per Boe, up from $19.90 per Boe in the prior year. Production volumes decreased from 2016, as a result of reduced drilling and completion activity. We expect oil, NGLs and gas sales to increase in 2018 due to improved commodity prices and an increase in production.

Oil, NGLs and gas sales for 2016 decreased $41 million, or 31%, to $90.3 million from $131.3 million in 2015. The decrease in oil, NGLs and gas sales was due to a decrease in average realized commodity prices ($17.4 million) and a decrease in production volumes ($23.6 million). In 2016, the average price we received for our production, before the effect of commodity derivatives, decreased 16% to $19.90 per Boe, down from $23.74 per Boe in the prior year. Production volumes decreased from 2015, as a result of reduced drilling and completion activity.

Net (loss) income. Net loss for 2017 was $112.4 million, or $1.35 per diluted share, compared to $52.2 million, or $1.26 per diluted share, for 2016. Net loss for 2017 included a tax provision of $76.4 million, a gain on debt extinguishment of $5.1 million due to the Exchange Transactions and a commodity derivative loss of $0.3 million. The increase in the net loss for 2017 was primarily due to the increase in our tax provision of $100.8 million. This resulted from our cumulative change in ownership following the Exchange Transactions, partially offset by the change in the corporate federal income tax rate. The increase in our tax provision was partially offset by an increase in revenues ($15 million), a decrease in operating expenses ($10.1 million), a decrease in interest expense ($6.2 million), a decrease in commodity derivative loss ($5.2 million) and the gain on debt extinguishment ($5.1 million).

Net loss for 2016 was $52.2 million, or $1.26 per diluted share, compared to $174.1 million, or $4.30 per diluted share, for 2015. Net loss for 2016 included a commodity derivative loss of $5.5 million. The decrease in the net loss for 2016 was primarily due to the impairment loss ($220.2 million) in 2015 and lower operating expenses excluding impairment ($48.4 million), partially offset by lower revenues ($41 million) due to depressed commodity prices and lower production and a decrease in income tax benefit ($69 million).

Oil, NGLs and gas production. Production for 2017 totaled 4,232 MBoe (11.6 MBoe/d), compared to 4,537 MBoe (12.4 MBoe/d) in 2016, a decrease of 7%. Production for 2017 was 26% oil, 35% NGLs and 39% natural gas, compared to 28% oil, 34% NGLs and 38% natural gas in 2016. The decrease in production in 2017 was the result of our reduced drilling and completion activity in 2016. We expect production to slightly increase in 2018 as a result of increased drilling activity in 2017 and an increased pace of well completions in 2018.

Production for 2016 totaled 4,537 MBoe (12.4 MBoe/d), compared to 5,532 MBoe (15.2 MBoe/d) in 2015, a decrease of 18%. Production for 2016 was 28% oil, 34% NGLs and 38% natural gas, compared to 34% oil, 31% NGLs and 35% natural gas in 2015. The decrease in production in 2016 was the result of our reduced drilling and completion activity in 2016.

Commodity derivative (loss) gain. The following table sets forth the components of our commodity derivative (loss) gain for the years ended December 31, 2017, 2016 and 2015 (dollars in thousands).

	Year Ended December 31,		
	2017	2016	2015
Net cash (payment) receipt on derivative settlements	$(4,359)	$6,132	$52,489
Non-cash fair value gain (loss) on derivatives	4,097	(11,616)	(33,214)
Commodity derivative (loss) gain	$(262)	$(5,484)	$19,275

Historically, we have not designated our derivative instruments as cash-flow hedges. Commodity derivative settlements are derived from the relative movement of commodity prices in relation to the fixed notional pricing in our derivative contracts for the respective years. As commodity prices increase or decrease, the fair value of the open portion of those positions decreases or increases, respectively. We record our open derivative instruments at fair value on our consolidated balance sheets as either derivative assets or liabilities. We record changes in such fair value in earnings on our consolidated statements of operations under the caption entitled “commodity derivative (loss) gain”. For 2018, we currently have 627,500 Bbls of oil hedged at a weighted average floor price of $56.37 per Bbl and a weighted average ceiling price of $57.81 per Bbl, 5,400,000 MMBtu of gas hedged at a weighted average price of $3.08 per MMBtu and 749,400 Bbls of NGLs hedged at weighted average prices of $11.42 per Bbl (C2-ethane), $32.53 per Bbl (C3-propane), $37.81 per Bbl (IC4-isobutane), $37.80 per Bbl (NC4-butane) and $56.36 per Bbl (C5 – Pentane).

Lease operating expenses. Our lease operating expenses (“LOE”) decreased $1.4 million, or 7%, for 2017, to $17.9 million ($4.23 per Boe) from $19.3 million ($4.24 per Boe) for 2016. The decrease in LOE in 2017 over 2016 was primarily due to increased efficiency in our water hauling operations, partially offset by an increase in compression rental and repair, well repairs, workovers and maintenance to manage production declines. In 2018, we expect LOE per Boe to slightly increase.

Our LOE decreased $9.7 million, or 34%, for 2016, to $19.3 million ($4.24 per Boe) from $29 million ($5.24 per Boe) for 2015. LOE per Boe in 2016 decreased $1.00, or 19%, from 2015. The decrease in LOE per Boe in 2016 over 2015 was primarily due to increased efficiency in our water hauling operations, lower pumpers and supervision costs due to a reduction in our workforce and a decrease in compressor rental and repair due to cost saving initiatives, partially offset by an increase in well repairs, workovers and maintenance to manage production declines.

The following tables summarize LOE (in millions) and LOE per Boe.

	Year Ended December 31,						
	2017		2016		Change		% Change
	$MM	Boe	$MM	Boe	$MM	Boe	(Boe)
Compressor rental and repair	$7.3	$1.71	$7.2	$1.58	$0.1	$0.13	8.2 %
Well repairs, workovers and maintenance	4.1	0.98	4.3	0.95	(0.2)	0.03	3.2
Water hauling and other	3.7	0.87	5.0	1.09	(1.3)	(0.22)	(20.2)
Pumpers and supervision	2.8	0.67	2.8	0.62	—	0.05	8.1
Total	$17.9	$4.23	$19.3	$4.24	$(1.4)	$(0.01)	(0.2)%

	Year Ended December 31,						
	2016		2015		Change		% Change
	$MM	Boe	$MM	Boe	$MM	Boe	(Boe)
Compressor rental and repair	$7.2	$1.58	$10.2	$1.84	$(3.0)	$(0.26)	(14.1)%
Well repairs, workovers and maintenance	4.3	0.95	4.3	0.79	0.0	0.16	20.3
Water hauling and other	5.0	1.09	9.2	1.66	(4.2)	(0.57)	(34.3)
Pumpers and supervision	2.8	0.62	5.3	0.95	(2.5)	(0.33)	(34.7)
Total	$19.3	$4.24	$29.0	$5.24	$(9.7)	$(1.00)	(19.1)%

Production and ad valorem taxes. Our 2017 production and ad valorem taxes increased approximately $0.4 million, or 5%, to $8.6 million from $8.2 million for 2016. The increase in production and ad valorem taxes was primarily the result of an increase in oil, NGLs and gas sales over 2016. Production and ad valorem taxes were approximately 8.2% and 9.1% of oil, NGLs and gas sales for the respective periods. The decrease in production and ad valorem taxes as a percentage of revenue was primarily due to a refund from the state of Texas for production taxes of $0.5 million relating to tax reimbursements.

Our 2016 production and ad valorem taxes decreased approximately $2.9 million, or 26%, to $8.2 million from $11.1 million for 2015. The decrease in production and ad valorem taxes was primarily the result of a decrease in oil, NGLs and gas sales over 2015. Production and ad valorem taxes were approximately 9.1% and 8.4% of oil, NGLs and gas sales for the respective periods. Production and ad valorem taxes as a percentage of revenue increased in 2016 due to an increase in ad valorem tax rates in 2016.

Exploration expense. We recorded $3.7 million, $3.9 million and $4.4 million of exploration expense for 2017, 2016 and 2015, respectively. The decrease in exploration expense in 2017 was primarily due to a decrease in lease expirations in the current year. Exploration expense for 2017 and 2016 resulted primarily from lease expirations in the Permian Basin. In 2015, exploration expense included $2.2 million related to the early termination fees of drilling contracts.

General and administrative expenses. Our general and administrative expenses ("G&A") decreased $0.4 million, or 2%, to $24.3 million ($5.75 per Boe) for 2017 from $24.7 million ($5.45 per Boe) for 2016. The decrease in G&A was primarily due to lower share-based compensation, partially offset by an increase in salaries and benefits and professional fees. In 2017 and 2016, G&A included $0.8 million and $1.3 million in expense related to cash-settled performance awards, respectively; these awards are re-measured each interim reporting period based on the fair market value of our common stock. Significant changes in the fair market value of our common stock will impact G&A per Boe.

Our G&A decreased $3.6 million, or 13%, to $24.7 million ($5.45 per Boe) for 2016 from $28.3 million ($5.12 per Boe) for 2015. The decrease in G&A was primarily due to lower share-based compensation, professional fees and other cost saving initiatives.

The following table summarizes G&A (in millions) and G&A per Boe.

	Year Ended December 31,							
	2017		2016		Change		% Change	
	$MM	Boe	$MM	Boe	$MM	Boe	(Boe)	
Salaries and benefits	$12.6	$2.99	$12.1	$2.68	$0.5	$0.31	11.6	%
Share-based compensation	4.7	1.10	6.3	1.38	(1.6)	(0.28)	(20.3	)
Professional fees	2.3	0.54	1.6	0.36	0.7	0.18	50.0	
Other	4.7	1.12	4.7	1.03	0.0	0.09	8.7	
Total	$24.3	$5.75	$24.7	$5.45	$(0.4)	$0.30	5.5	%

	Year Ended December 31,							
	2016		2015		Change		% Change	
	$MM	Boe	$MM	Boe	$MM	Boe	(Boe)	
Salaries and benefits	$12.1	$2.68	$12.1	$2.19	$0.0	$0.49	22.4	%
Share-based compensation	6.3	1.38	8.0	1.44	(1.7)	(0.06)	(4.2	)
Professional fees	1.6	0.36	2.9	0.52	(1.3)	(0.16)	(30.8	)
Other	4.7	1.03	5.3	0.97	(0.6)	0.06	6.2	
Total	$24.7	$5.45	$28.3	$5.12	$(3.6)	$0.33	6.4	%

Termination costs. We did not recognize termination costs in 2017 or 2016. In 2015, we recorded $1.4 million of termination costs in connection with a reduction in our workforce.

Depletion, depreciation and amortization expense. Our depletion, depreciation and amortization expense (“DD&A”) decreased $8.5 million, or 11%, to $70.5 million for 2017, from $79 million for 2016. The decrease in DD&A in 2017 over 2016 was primarily attributable to a decrease in production. Our DD&A per Boe decreased by $0.76, or 4%, to $16.66 per Boe for 2017, compared to $17.42 per Boe for 2016. The decrease in DD&A per Boe over the prior-year period was primarily due to lower oil and gas property carrying costs relative to estimated proved developed reserves.

DD&A decreased $30.3 million, or 28%, to $79 million for 2016, from $109.3 million for 2015. The decrease in DD&A in 2016 over 2015 was primarily attributable to a decrease in production. Our DD&A per Boe decreased by $2.34, or 12%, to $17.42 per Boe for 2016, compared to $19.76 per Boe for 2015. The decrease in DD&A per Boe over the prior-year period was primarily due to lower oil and gas property carrying costs relative to estimated proved developed reserves.

Impairment of oil and gas properties. We did not recognize an impairment on our oil and gas properties in 2017 or 2016. We recognized a non-cash impairment loss of $220.2 million in 2015, due primarily to a decrease in our estimated future cash flows related to forward commodity prices. The impairment loss was primarily attributable to vertical Canyon wells in Ozona Northeast. Significant inputs used to assess proved property impairment include estimates of (i) future sales prices for oil and gas based on NYMEX strip prices, (ii) pricing adjustments for differentials, (iii) production costs, (iv) capital expenditures, (v) future oil and gas reserves to be recovered and the timing of recovery and (vi) discount rate.

Interest expense, net. The following table sets forth interest expense, weighted average interest rates and weighted average debt balances for the years ended December 31, 2017, 2016 and 2015 (dollars in thousands).

	Year Ended December 31,		
	2017	2016	2015
Interest expense	$21,053	$27,259	$25,066
Weighted average interest rate	5.4 %	5.4 %	5.1 %
Weighted average debt balance	$388,629	$507,605	$491,528

Interest expense for the years ended December 31, 2017, 2016 and 2015 includes amortization of debt issuance costs of $0.9 million, $1.4 million and $1.6 million, respectively. Interest expense, net, decreased $6.2 million or 23%, to $21.1 million for 2017, compared to $27.3 million for 2016. This decrease was primarily due to the reduction in our interest expense on outstanding Senior Notes ($9.8 million), partially offset by an increase in the applicable margin rates, outstanding borrowings and floating interest rates under our revolving credit facility.

Interest expense, net, increased $2.2 million or 9%, to $27.3 million for 2016, compared to $25.1 million for 2015. This increase was due to higher interest expense from an increased weighted average debt balance and the applicable margin rates under our revolving credit facility, partially offset by interest savings of $1.3 million from our 2015 repurchase of $19.7 million aggregate face value of our Senior Notes on the open market.

Write-off of debt issuance costs. In 2016, we recorded a $0.6 million write-off of unamortized debt issuance costs, related to the third amendment of our revolving credit facility, due to the reduction in our borrowing base from $450 million to $325 million.

Gain on extinguishment of debt. In 2017, we recognized a gain of $5.1 million on the Exchange Transactions for the difference between the fair market value of the shares issued, a Level 1 fair value measurement, and the net carrying value of the Senior Notes exchanged. In 2016, we did not repurchase or retire any outstanding debt. In 2015, we repurchased a portion of our Senior Notes in the open market with an aggregate face value of $19.7 million for a purchase price of $8.8 million, including accrued interest. This resulted in a gain on extinguishment of debt of $10.6 million.

Other income. Other income for the years ended December 31, 2017, 2016 and 2015 was $32,000, $1.5 million and $0.2 million, respectively. In 2016, we recorded a contractual settlement of $1.4 million in other income.

Income taxes. In 2017, we recognized an income tax provision of $76.4 million, compared to an income tax benefit of $24.4 million and $93.4 million in 2016 and 2015, respectively. The following table reconciles our income tax expense for the years ended December 31, 2017, 2016 and 2015, to the U.S. federal statutory rate of 35% (dollars in thousands).

Years Ended December 31,

	2017	2016	2015
Statutory tax at 35%	$(12,578)	$(26,831)	$(93,628)
State taxes, net of federal impact	528	578	(1,463)
Share-based compensation tax shortfall	1,279	1,826	1,939
Permanent differences	11	11	26
Other differences	30	(2)	(1,035)
Change in federal tax rate	(51,939)	—	—
Write-off of deferred tax assets	139,090	—	756
Total	$76,421	$(24,418)	$(93,405)

In 2017, the Exchange Transactions triggered a cumulative change in ownership of our common stock by more than 50% under Section 382 of the Internal Revenue Code as of March 22, 2017. This established an annual limitation on the future use of our pre-change net operating losses (“NOLs”). Accordingly, we reduced our NOL deferred tax assets by $139.1 million.

On December 22, 2017, the Tax Cuts and Jobs Act was enacted which, among other things, lowered the U.S. Federal income tax rate applicable to corporations from 35% to 21% and repealed the corporate alternative minimum tax. We recorded a net tax benefit of $51.9 million to reflect the impact of the Tax Cuts and Jobs Act as of December 31, 2017, as it is required to reflect the change in the period in which the law is enacted. We expect our effective income tax rate to decrease in 2018 due to the reduction in the U.S. statutory federal income tax rate.

Liquidity and Capital Resources

We generally will rely on cash generated from operations, to the extent available, borrowings under our revolving credit facility and, to the extent that credit and capital market conditions will allow, future equity and debt offerings to satisfy our liquidity needs. Our ability to fund planned capital expenditures and to make acquisitions depends upon commodity prices, our future operating performance, availability of borrowings under our revolving credit facility, and more broadly, on the availability of equity and debt financing, which is affected by prevailing economic conditions in our industry and financial, business and other factors, some of which are beyond our control. We cannot predict whether additional liquidity from equity or debt financings beyond our revolving credit facility will be available on acceptable terms, or at all, in the foreseeable future.

Our cash flow from operations is driven by commodity prices, production volumes and the effect of commodity derivatives. Cash flows from operations are primarily used to fund exploration and development of our oil and gas properties. If commodity prices decline from current levels, our operating cash flows will decrease and our lenders may reduce our borrowing base, thus limiting the amounts available to fund future capital expenditures. If we are unable to replace our oil, NGLs and gas reserves through acquisitions, development and exploration, we may also suffer a reduction in operating cash flows and access to funds under our revolving credit facility. At December 31, 2017, we were in compliance with all required covenants under our revolving credit facility. If commodity prices decline from current levels, this may trigger non-compliance with required debt covenants in the future and otherwise adversely impact our ability to operate.

We believe we currently have adequate liquidity from cash generated from operations and unused borrowing capacity under our revolving credit facility for current working capital needs and maintenance of our current development plan. However, we may determine to use various financing sources, including the issuance of common stock, preferred stock, debt, convertible securities and other securities for future development of reserves, acquisitions, additional working capital or other liquidity needs, if such financing is available on acceptable terms. We cannot guarantee that such financing will be available on acceptable terms or at all. Using some of these financing sources may require approval from the lenders under our revolving credit facility.

In 2017, we completed the Exchange Transactions, which reduced our Senior Notes by $145.1 million and resulted in $44.3 million in interest savings over the remaining term of the Senior Notes. The Exchange Transactions improved our operating cash flow through the reduction of interest expense. Additionally, in 2017, we completed the Bolt-On Acquisition, which we expect will benefit our future operating cash flow through an increase in production volumes.

Liquidity

We define liquidity as funds available under our revolving credit facility plus year-end net cash and cash equivalents. Our liquidity is subject to our continued compliance with the covenants under our revolving credit facility. At December 31, 2017, we were in compliance with all of our covenants, and there were no existing defaults or events of default under our debt instruments. See Note 3 to our consolidated financial statements for additional discussion of the covenants under our revolving credit facility. At December 31, 2017, we had $291 million in borrowings outstanding under our revolving credit facility and $21,000 in cash and cash equivalents, compared to $273 million in borrowings outstanding under our revolving credit facility at both December 31, 2016, and 2015, and $21,000 and $0.6 million in cash and cash equivalents at December 31, 2016, and 2015, respectively. Our liquidity position at December 31, 2017, decreased compared to December 31, 2016, due to an increase in the outstanding borrowings under our revolving credit facility. In December 2017, we entered into a fourth amendment to our revolving credit facility, which among other things, extended the maturity date of the revolving credit facility from May 7, 2019 to May 7, 2020 and reaffirmed the aggregate lender commitments of $325 million.

The borrowing base under our revolving credit facility is redetermined semi-annually based on our oil, NGLs and gas reserves. In May 2016, the borrowing base decreased from $450 million to $325 million. In September 2015, the borrowing base decreased from $525 million to $450 million. In April 2015, the borrowing base decreased from $600 million to $525 million. The reductions in our borrowing base in 2016 and 2015 were primarily attributable to decreases in commodity prices. We expect that our next regularly scheduled borrowing base review process will be completed in the second quarter of 2018.

The following table summarizes our liquidity position at December 31, 2017, 2016 and 2015 (in thousands).

	Year Ended December 31,		
	2017	2016	2015
Credit Facility commitments	$325,000	$325,000	$450,000
Cash and cash equivalents	21	21	600
Long-term debt — Credit Facility	(291,000)	(273,000)	(273,000)
Undrawn letters of credit	(325)	(575)	(325)
Liquidity	$33,696	$51,446	$177,275

Working Capital

Our working capital is affected primarily by the fair value of our commodity derivative positions and our capital spending program. At December 31, 2017, we had a working capital deficit of $8.4 million, compared to a working capital deficit of $13.9 million and $8.1 million at December 31, 2016 and 2015, respectively. The change in working capital during 2017 was primarily attributable to prepayment of hydraulic fracturing services and changes in fair value of our commodity derivatives partially offset by an increase in accrued liabilities due to an increase in capital expenditures. The change in working capital during 2016 was primarily attributable to changes in fair value of our commodity derivatives partially offset by a decrease in accounts payable and accrued liabilities due to a decrease in capital expenditures and cost reductions. The change in working capital during 2015 was primarily attributable to a decrease in accounts payable and accrued liabilities due to a decrease in our capital expenditures. To the extent we operate or end 2018 with a working capital deficit, we expect such deficit to be offset by liquidity available under our revolving credit facility.

Cash Flows

The following table summarizes our sources and uses of funds for the periods noted (in thousands).

	Year Ended December 31,		
	2017	2016	2015
Cash flows provided by operating activities	$37,454	$26,081	$102,716
Cash flows used in investing activities	(52,409)	(23,890)	(217,347)
Cash flows (used in) provided by financing activities	14,955	(2,770)	114,799
Net (decrease) increase in cash and cash equivalents	$—	$(579)	$168

For 2017, our primary sources of cash were from operating activities and financing activities. Approximately $37.5 million of cash from operations and $15 million of cash from financing activities were used to fund our development project in the Permian Basin. Cash flows used in investing activities were higher in 2017 compared to 2016, primarily due to an increase in capital expenditures of $27.3 million as a result of improved commodity prices and a decrease in interest expense as a result of the Exchange Transactions. Cash flows provided by financing activities were higher in 2017 primarily due to $18 million in net borrowings on our revolving credit facility in 2017, compared to no net borrowings on our revolving credit facility in 2016.

For 2016, our primary source of cash was from operating activities. Approximately $23.9 million of cash from operations was used to fund our $19.8 million of capital expenditures in 2016 for our development project in the Permian Basin and $4.1 million for changes in working capital related to investing activities. Cash flows used in investing activities were lower in 2016 compared to 2015, primarily due to a decrease in capital expenditures of

$131.4 million as a result of depressed commodity prices. Cash flows used in financing activities were lower in 2016 primarily due to no net borrowings on our revolving credit facility in 2016, compared to $123 million in net borrowing on our credit facility in 2015.

For 2015, our primary sources of cash were from operating activities and financing activities. Approximately $102.7 million of cash from operations and $114.8 million of cash from financing activities were used to fund our development project in the Permian Basin. Cash flows used in investing activities were lower in 2015 compared to 2014, primarily due to a decrease in capital expenditures of $239.3 million as a result of depressed commodity prices.

Operating Activities

For 2017, our cash flows from operations were used primarily for drilling and development activities in the Permian Basin. Cash flows from operating activities increased by $11.4 million, or 44%, to $37.5 million in 2017 from $26.1 million in 2016. The increase in cash flows from operating activities in 2017 from 2016 was primarily due to an increase in oil, NGLs and gas sales as a result of higher commodity prices and a decrease in interest expense as a result of the Exchange Transactions, partially offset by an increase in realized losses from our commodity derivative activity.

For 2016, our cash flows from operations were used primarily for drilling and development activities in the Permian Basin. Cash flows from operating activities decreased by $76.6 million, or 75%, to $26.1 million in 2016 from $102.7 million in 2015. The decrease in cash flows from operating activities in 2016 from 2015 was primarily due to a decrease in oil, NGLs and gas sales as a result of lower commodity prices and production, a decrease in realized gains from our commodity derivative activity, partially offset by a decrease in operating expenses.

For 2015, our cash flows from operations were used primarily for drilling and development activities in the Permian Basin. Cash flows from operating activities decreased by $68.9 million, or 40%, to $102.7 million in 2015 from $171.6 million in 2014. The decrease in cash flows from operating activities in 2015 from 2014 was primarily due to a decrease in oil, NGLs and gas sales as a result of lower commodity prices and the timing of receipts and payments of working capital components.

Investing Activities

During the years ended December 31, 2017, 2016 and 2015, we invested $47.1 million, $19.8 million and $151.2 million, respectively, for capital expenditures on oil and gas properties. Cash flows used in investing activities was higher in 2017 compared to 2016 primarily due to an increase in capital expenditures. Our capital expenditures for 2017 were primarily attributable to drilling and development ($44.2 million), infrastructure projects and equipment ($3.6 million), acreage extensions ($0.2 million), partially offset by a sales tax refund ($0.9 million). Cash used in investing activities also included changes in working capital associated with investing activities ($5.3 million) primarily related to prepayment of hydraulic fracturing services. Cash flows used in investing activities were lower in 2016 compared to 2015, primarily due to a decrease in capital expenditures of $131.4 million as a result of depressed commodity prices.

The following table is a summary of capital expenditures related to our oil and gas properties (in thousands).

	Years Ended December 31,

	2017	2016	2015
Permian Basin	$43,208	$16,692	$139,103
Permian Basin acquisitions	—	—	—
Subtotal	43,208	16,692	139,103
East Texas Basin	—	—	—
Exploratory projects	—	—	—
Infrastructure projects, equipment and 3-D seismic	3,612	3,079	11,422
Lease acquisitions and extensions	231	17	653
Total	$47,051	$19,788	$151,178

Financing Activities

The following is a description of our financing activities in 2017, 2016 and 2015.

- In 2017, we completed the Exchange Transactions, which reduced our Senior Notes by $145.1 million and provided for in $44.3 million in interest savings over the remaining term of the Senior Notes. The Exchange Transactions improved our operating cash flow through the reduction of interest expense. We incurred equity issuance costs of $2.8 million related to the Exchange Transactions, which were recorded as a reduction to additional paid-in capital.
- In December 2017, we entered into a fourth amendment to the revolving credit facility. The fourth amendment, among other things, (a) extended the maturity date of the revolving credit facility from May 7, 2019, to May 7, 2020, (b) reaffirmed the aggregate lender commitments of $325 million, (c) increased the applicable margin rates on borrowings by 50 basis points, and (d) required the Company to hedge 50% of the Company’s estimated 2018 oil and gas production from proved developed producing (“PDP”) reserves. In connection with the fourth amendment to the revolving credit facility, we incurred $1 million of debt issuance costs.
- In May 2016, the lenders under our revolving credit facility completed their semi-annual borrowing base redetermination and decreased the aggregate lender commitments to $325 million from $450 million. In November 2016, the lenders under our revolving credit facility completed their semi-annual borrowing base redetermination, reaffirming the aggregate lender commitments of $325 million.
- In 2015, we repurchased a portion of our Senior Notes in the open market with an aggregate face value of $19.7 million for a purchase price of $8.8 million, including accrued interest.

In 2017, we increased the net outstanding balance under our revolving credit facility by $18 million, compared to no net increase or decrease in borrowings under our revolving credit facility in 2016, and $123 million of net borrowings under our revolving credit facility in 2015.

As market conditions warrant and subject to our contractual restrictions in our revolving credit facility or otherwise, liquidity position and other factors, we may from time to time seek to recapitalize, refinance or otherwise restructure our capital structure. We may accomplish this through open market or privately negotiated transactions, which may include, among other things, repurchases of our common stock or outstanding debt, debt for debt or debt for equity exchanges or refinancings, and private or public equity raises and rights offerings. Many of these alternatives may require the consent of current lenders, stockholders or bond holders, and there is no assurance that we will be able to execute any of these alternatives on acceptable terms or at all. The amounts involved in any such transaction, individually or in the aggregate, may be material.

Revolving Credit Facility

We have a $1 billion revolving credit facility with a borrowing base and aggregate lender commitments of $325 million. The borrowing base is redetermined semi-annually based on our oil and gas reserves. We or the lenders can each request one additional borrowing base redetermination each calendar year. We expect that our next regularly scheduled borrowing base review process will be completed in the second quarter of 2018.

The maturity date under our revolving credit facility is May 7, 2020. Borrowings bear interest based on the agent bank’s prime rate plus an applicable margin ranging from 2% to 3%, or the sum of the London Interbank Offered Rate (“LIBOR”) rate plus an applicable margin ranging from 3% to 4%. Margins vary based on the borrowings outstanding compared to the borrowing base. In addition, we pay an annual commitment fee of 0.50% of unused borrowings available under our revolving credit facility.

We had outstanding borrowings of $291 million and $273 million under our revolving credit facility at December 31, 2017 and 2016, respectively. The weighted average interest rate applicable to borrowings under our revolving credit facility in 2017 was 4.5%. We also had outstanding unused letters of credit under our revolving credit facility totaling $0.3 million at December 31, 2017, which reduce amounts available for borrowing under our revolving credit facility.

Obligations under our revolving credit facility are secured by mortgages on substantially all of the oil and gas properties of the Company and its subsidiaries. The Company is required to maintain liens covering the oil and gas properties of the Company and its subsidiaries representing at least 95% of the total value of all oil and gas properties of the Company and its subsidiaries.

On December 21, 2017, we entered into a fourth amendment to the revolving credit facility. The fourth amendment, among other things, (a) extended the maturity date of the revolving credit facility from May 7, 2019, to May 7, 2020, (b) increased the applicable margin rates on borrowings by 50 basis points, and (c) required the Company to hedge 50% of the Company's estimated 2018 oil and gas production from PDP reserves. In connection with the fourth amendment to the revolving credit facility, we incurred $1 million of debt issuance costs.

On May 3, 2016, we entered into a third amendment to our revolving credit facility. Specifically, the third amendment (a) decreased the borrowing base to $325 million from $450 million, (b) increased the applicable margin rates on borrowings by 100 basis points, (c) permits the Company to issue up to $150 million of second lien indebtedness, subject to various conditions and limitations, and (d) permits the Company to repurchase outstanding debt with proceeds of certain asset sales, equity issuances or second lien indebtedness.

On December 30, 2014, we entered into a second amendment to our revolving credit facility. The second amendment, among other things, modified the negative covenant allowing optional redemption of unsecured notes.

Covenants

Our revolving credit facility contains three principal financial covenants:

- a consolidated interest coverage ratio covenant that requires us to maintain a ratio of (i) consolidated EBITDAX for the period of four fiscal quarters then ending to (ii) Cash Interest Expense for such period as of the last day of any fiscal quarter of not less than 1.5 to 1.0 through December 31, 2017, a ratio of not less than 1.75 to 1.0 through December 31, 2018, a ratio of not less than 2.25 to 1.0 through December 31, 2019, and 2.5 to 1.0 thereafter. EBITDAX is defined as consolidated net (loss) income plus (i) interest expense, net, (ii) income tax provision (benefit), (iii) depreciation, depletion, amortization, (iv) exploration expenses and (v) other noncash loss or expense (including share-based compensation and the change in fair value of any commodity derivatives), less noncash income. Cash Interest Expense is calculated as interest expense, net less amortization of debt issuance costs. At December 31, 2017, our consolidated interest coverage ratio was 2.7 to 1.0;
- a consolidated modified current ratio covenant that requires us to maintain a ratio of not less than 1.0 to 1.0 as of the last day of any fiscal quarter. The consolidated modified current ratio is defined as the ratio of (i) current assets plus funds available under our revolving credit facility, less the current derivative asset, to (ii) current liabilities less the current derivative liability. At December 31, 2017, our consolidated modified current ratio was 2.1 to 1.0; and
- a consolidated total leverage ratio covenant that imposes a maximum permitted ratio of (i) Total Debt to (ii) EBITDAX for the period of four fiscal quarters then ending of no more than 5.0 to 1.0, as of the last day of any fiscal quarter from March 31, 2019, through June 30, 2019, thereafter no more than 4.75 to 1.0 as of the last day of any fiscal quarter through December 31, 2019, and (iii) no more than 4.0 to 1.0 as of the last day of any fiscal quarter thereafter. Total Debt is defined as the face or principal amount of debt. Our leverage ratio is currently above the level that will be required as of March 31, 2019.

Our revolving credit facility also contains covenants restricting cash distributions and other restricted payments, transactions with affiliates, incurrence of other debt, consolidations and mergers, the level of operating leases, asset sales, investment in other entities and liens on properties.

The obligations of the Company may be accelerated upon the occurrence of an Event of Default (as defined in our revolving credit facility). Events of default include customary events for a financing agreement of this type, including, without limitation, payment defaults, the inaccuracy of representations and warranties, defaults in the performance of affirmative or negative covenants, defaults on other indebtedness of the Company or its subsidiaries, bankruptcy or related defaults, defaults related to judgments and the occurrence of a Change of Control (as defined in our revolving credit facility), which includes instances where a third party becomes the beneficial owner of more than 50% of the Company's outstanding equity interests entitled to vote.

To date, we have experienced no disruptions in our ability to access our revolving credit facility. However, our lenders have substantial ability to reduce our borrowing base on the basis of subjective factors, including the loan collateral value that each lender, in its discretion and using the methodology, assumptions and discount rates as such lender customarily uses in evaluating oil and gas properties, assigns to our properties.

Senior Notes

In June 2013, we completed our public offering of $250 million principal amount of 7% Senior Notes due 2021. Annual interest on the Senior Notes is payable semi-annually on June 15 and December 15. We received net proceeds from the issuance of the Senior Notes of approximately $243 million, after deducting fees and expenses. We used a portion of the net proceeds from the offering to repay all outstanding borrowings under our revolving credit facility. In 2014, we used the remaining net proceeds to fund our capital expenditures and for general working capital needs. During the year ended December 31, 2015, we repurchased Senior Notes in the open market with an aggregate face value of $19.7 million for a purchase price of $8.8 million, including accrued interest. This resulted in a gain on extinguishment of debt of $10.6 million.

During the year ended December 31, 2017, we completed the Exchange Transactions which reduced the outstanding principal balance of our Senior Notes by $145.1 million and reduced future interest payments by $44.3 million over the remaining term of the Senior Notes.

We issued the Senior Notes under a senior indenture dated June 11, 2013, among the Company, our subsidiary guarantors and Wilmington Trust, National Association, as successor trustee. The senior indenture, as supplemented by a supplemental indenture dated June 11, 2013, is referred to as the “Indenture.”

On December 20, 2016, we entered into the second supplemental indenture (the “Second Supplemental Indenture”), which became effective on January 27, 2017, in connection with the closing of the Initial Exchange. The Second Supplemental Indenture (i) eliminated certain definitions and references to definitions contained in the Indenture, (ii) eliminated and revised, as applicable, certain events of default contained in the Indenture, (iii) eliminated certain conditions to consolidation, merger, conveyance, transfer or lease contained in the Indenture, (iv) eliminated certain covenants contained in the Indenture, including substantially all of the restrictive covenants set forth therein, and (v) supplemented and amended the Senior Notes and the securities guarantees, as and to the same extent as the Indenture has been amended and supplemented in accordance with the preceding clauses (i), (ii), (iii) and (iv).

We may redeem some or all of the Senior Notes at specified redemption prices, plus accrued and unpaid interest to the redemption date. The Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by each of our subsidiaries, subject to certain customary release provisions. A subsidiary guarantor may be released from its obligations under the guarantee:

- in connection with any sale or other disposition of all or substantially all of the assets of that guarantor (including by way of merger or consolidation) to a person that is not (either before or after giving effect to such transaction) the Company or a subsidiary guarantor, if the sale or other disposition otherwise complies with the indenture;
- in connection with any sale or other disposition of the capital stock of that guarantor to a person that is not (either before or after giving effect to such transaction) the Company or a subsidiary guarantor, if that guarantor no longer qualifies as a subsidiary of the Company as a result of such disposition and the sale or other disposition otherwise complies with the indenture;
- if the Company designates any restricted subsidiary that is a guarantor to be an unrestricted subsidiary in accordance with the indenture;
- upon defeasance or covenant defeasance of the notes or satisfaction and discharge of the indenture, in each case, in accordance with the indenture;

- upon the liquidation or dissolution of that guarantor, provided that no default or event of default occurs under the indenture as a result thereof or shall have occurred and is continuing; or

- in the case of any restricted subsidiary that, after the issue date of the notes is required under the indenture to guarantee the notes because it becomes a guarantor of indebtedness issued or an obligor under the revolving credit facility with respect to the Company and/or its subsidiaries, upon the release or discharge in full from its (x) guarantee of such indebtedness or (y) obligation under such revolving credit facility, in each case, which resulted in such restricted subsidiary's obligation to guarantee the notes.

As a result of the Second Supplemental Indenture, the Indenture contains limited events of default.

At December 31, 2017, we were in compliance with all of our covenants, and there were no existing defaults or events of default, under our debt instruments.

Contractual Obligations

As of December 31, 2017, our contractual obligations include long-term debt, operating lease obligations, asset retirement obligations and employment agreements with our executive officers.

In April 2007, we signed a five-year lease for approximately 13,000 square feet of office space in Fort Worth, Texas. Since that time, we have expanded the lease to approximately 35,000 square feet and extended the term to September 30, 2021.

Our asset retirement obligation primarily represents the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties at the end of their productive lives, in accordance with applicable federal, state and local laws. We determine our asset retirement obligation by calculating the present value of estimated cash flows related to the liability. The retirement obligation is recorded as a liability at its estimated present value as of the asset's inception, with an offsetting increase to proved properties. Periodic accretion of discount of the estimated liability is recorded as an expense in the income statement.

At December 31, 2017, we had outstanding employment agreements with all four of our executive officers that contained automatic renewal provisions providing that such agreements may be automatically renewed for successive terms of one year unless the employment is terminated at the end of the term by written notice given to the employee not less than 60 days prior to the end of such term. Our maximum commitment under the employment agreements, which would apply if the employees covered by these agreements were each terminated without cause, was approximately $6.3 million at December 31, 2017. This estimate assumes the maximum potential bonus for 2017 is earned by each executive officer during 2017.

The following table summarizes these commitments as of December 31, 2017 (in thousands).

	Payments Due By Period				
Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Credit agreement[1]	$291,000	$—	$291,000	$—	$—
Senior Notes[2]	106,124	5,967	11,934	88,223	—
Operating lease obligations[3]	3,265	852	1,736	677	—
Asset retirement obligations[4]	11,065	—	—	—	11,065
Employment agreements with executive officers	8,370	7,904	466	—	—

and cash-settled performance awards [5]					
Total	$419,824	$14,723	$305,136	$88,900	$11,065

(1) Credit agreement matures on May 7, 2020. See Note 3 to our consolidated financial statements for a discussion regarding interest payable under our revolving credit facility.
(2) 7% Senior Notes due 2021, including interest payable semi-annually on June 15 and December 15.
(3) Operating lease obligations are for office space and equipment.
(4) See Note 1 to our consolidated financial statements for a discussion of our asset retirement obligations.

(5) See Note 5 to our consolidated financial statements for a discussion of our cash-settled performance awards. The amount above assumes that performance criteria of the cash-settled performance awards are met.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of our consolidated financial statements requires us to make estimates and assumptions that affect our reported results of operations and the amount of reported assets, liabilities and proved oil and gas reserves. Some accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. Actual results may differ from the estimates and assumptions used in the preparation of our consolidated financial statements. Described below are the most significant policies we apply in preparing our consolidated financial statements, some of which are subject to alternative treatments under GAAP. We also describe the most significant estimates and assumptions we make in applying these policies. See Note 1 to our consolidated financial statements.

Segment reporting is not applicable to us as we have a single, company-wide management team that administers all significant properties as a whole, rather than by discrete operating segments. We track only basic operational data by area. We do not maintain complete separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis. We use the successful efforts method of accounting for our oil and gas activities.

Successful Efforts Method of Accounting

Accounting for oil and gas activities is subject to special, unique rules. We use the successful efforts method of accounting for our oil and gas activities. The significant principles for this method are:

- costs to acquire mineral interests in oil and gas properties and to drill and equip development wells and related asset retirement costs are capitalized. Costs to drill exploratory wells are capitalized pending determination of whether the wells have proved reserves;
- dry holes for exploratory wells are expensed and dry holes for development wells are capitalized;
- geological and geophysical evaluation costs are expensed as incurred; and
- capitalized costs related to proved oil and gas properties, including wells and related equipment and facilities, are evaluated for impairment based on an analysis of undiscounted future net cash flows in accordance with ASC 360. If undiscounted cash flows are insufficient to recover the net capitalized costs related to proved properties, then we recognize an impairment charge in income from operations equal to the difference between the net capitalized costs related to proved properties and their estimated fair values based on the present value of the related future net cash flows.

Proved Reserves

For the year ended December 31, 2017, we engaged DeGolyer and MacNaughton, independent petroleum engineers, to prepare independent estimates of the extent and value of 100% of our reported proved reserves, in accordance with rules and guidelines established by the SEC.

Estimates of proved oil and gas reserves directly impact financial accounting estimates including DD&A, evaluation of impairment of properties and the calculation of plugging and abandonment liabilities. 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. The process of estimating quantities of proved reserves is very complex, requiring significant subjective decisions in the evaluation of all geological, engineering and economic data for each reservoir. The data for any reservoir may change substantially over time due to results from operational activity. Proved reserve volumes at December 31, 2017, were estimated based on the average of the closing price on the first day of each month for the 12-month period prior to

December 31, 2017, for oil, NGLs and gas in accordance with SEC rules. Changes in commodity prices and operations costs may increase or decrease estimates of proved oil, NGLs and natural gas reserves. Depletion expense for our oil and gas properties is determined using our estimates of proved oil, NGLs and gas reserves.

See also Item 2. "Properties — Proved Oil and Gas Reserves" and Note 10 to our consolidated financial statements in this report for additional information regarding our estimated proved reserves.

Derivative Instruments and Commodity Derivative Activities

Derivative assets and liabilities on our commodity derivative contracts, at fair value, are included on our consolidated balance sheets as current or non-current assets or liabilities based on the anticipated timing of cash settlements under the related contracts. Cash settlements under our commodity derivative contracts and changes in the fair value of our commodity derivative contracts are recorded in earnings as they occur and included in commodity derivative (loss) gain on our consolidated statements of operations. We estimate the fair values of swap or collar contracts based on the present value of the difference in exchange-quoted forward price curves and contractual settlement prices multiplied by notional quantities. We internally valued the option contracts using industry-standard option pricing models and observable market inputs. We use our internal valuations to determine the fair values of the contracts that are reflected on our consolidated balance sheets.

We are exposed to credit losses in the event of nonperformance by the counterparties on our commodity derivatives positions and have considered the exposure in our internal valuations. However, we do not anticipate nonperformance by the counterparties over the term of the commodity derivatives positions.

We enter into financial swaps and collars to mitigate portions of the risk of market price fluctuations related to future oil, NGLs and gas production. All derivative instruments are recorded as derivative assets and liabilities at fair value in the balance sheet, and the changes in derivative's fair value are recognized as current income or expense in the consolidated statement of operations.

For the years ended December 31, 2017 and 2016 we recognized commodity derivative losses of $0.3 million and $5.5 million, respectively; compared to commodity derivative gains of $19.3 million for the year ended December 31, 2015.

Asset Retirement Obligation

Our asset retirement obligation primarily represents the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties at the end of their productive lives, in accordance with applicable federal, state and local laws. We determine our asset retirement obligation by calculating the present value of estimated cash flows related to the liability. The retirement obligation is recorded as a liability at its estimated present value as of the asset's inception, with an offsetting increase to proved properties. Periodic accretion of discount of the estimated liability is recorded as an expense in the income statement.

Our liability is determined using significant assumptions, including current estimates of plugging and abandonment costs, annual inflation of these costs, the productive lives of wells and our risk-adjusted interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation.

Impairment of Long-Lived Assets

All of our long-lived assets are monitored for potential impairment when circumstances indicate that the carrying value of an asset may be greater than its future net cash flows. The evaluations involve a significant amount of judgment since the results are based on estimated future events, such as future sales prices for oil, NGLs and gas, future costs to produce these products, estimates of future oil and gas reserves to be recovered and the timing thereof, the economic and regulatory climates and other factors. The need to test an asset for impairment may result from significant declines in commodity prices or downward revisions to estimated quantities of oil and gas reserves. Any assets held for sale are reviewed for impairment when we approve the plan to sell. Estimates of anticipated sales prices are highly judgmental and subject to material revision in future periods. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges will be recorded. We recorded no impairment of our proved properties for the years ended December 31, 2017 or 2016. For the year ended December 31, 2015, we recognized a non-cash impairment loss of $220.2 million, primarily attributable to vertical Canyon wells in Ozona Northeast. See Note 7 to our consolidated financial statements in this report for additional information regarding the significant inputs and methodology used in determining the impairment loss.

Provision for Income Taxes

We estimate our provision for income taxes using historical tax basis information from prior years' income tax returns, along with the estimated changes to such bases from current-period activity and enacted tax rates. When tax returns are filed, it is highly certain that some positions taken would be sustained upon examination by the taxing authorities, while others are subject to uncertainty about the merits of the position taken or the amount of the position that would be ultimately sustained. The benefit of a tax position is recognized in the financial statements in the period during which, based on all available evidence, management believes it is more likely than not that the position will be sustained upon examination, including the resolution of appeals or litigation processes, if any. Tax positions taken are not offset or aggregated with other positions. Tax positions that meet the more-likely-than-not recognition threshold are measured as the largest amount of tax benefit that is more than 50% likely of being realized upon settlement with the applicable taxing authority. The portion of the benefits associated with tax positions taken that exceeds the amount measured as described above is reflected as a liability for unrecognized tax benefits in the accompanying balance sheet along with any associated interest and penalties that would be payable to the taxing authorities upon examination. Interest and penalties associated with unrecognized tax benefits are classified as additional income taxes in our consolidated statements of operations. Additionally, we compare liabilities to actual settlements of such assets or liabilities during the current period to identify considerations that might affect the current period's estimate.

We monitor our deferred tax assets by jurisdiction to assess their potential realization, and a valuation allowance is recognized on deferred tax assets when we believe that certain of these assets are more likely than not to be realized. In performing this review, we make estimates and assumptions regarding projected future taxable income, the expected timing of reversals of existing temporary differences and the implementation of tax planning strategies. To the extent that a valuation allowance is established or changed during any period, we would recognize expense or benefit within our consolidated tax expense. We currently have a valuation allowance of $0.5 million on our deferred tax assets, after accounting for the change in the corporate federal income tax rate under the Tax Cuts and Jobs Act.

Valuation of Share-Based Compensation

Our 2007 Plan allows grants of stock and options to employees and outside directors. Granting of awards may increase our G&A, subject to the size and timing of the grants. See Note 5 to our consolidated financial statements in this report for additional information.

In accordance with GAAP, we calculate the fair value of share-based compensation using various valuation methods. The valuation methods require the use of estimates to derive the inputs necessary to determine fair value. We use (i) the closing stock price on the date of grant for the fair value of restricted stock awards, including performance-based awards, (ii) the Monte Carlo simulation method for the fair value of market-based awards, (iii) the fair market value of our common stock on the valuation date for cash-settled performance awards and (iv) the Black-Scholes option price model to measure the fair value of stock options.

Effects of Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2017, 2016 or 2015. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and may increase the cost to acquire or replace property and equipment. It may also increase the cost of labor or supplies.

Off-Balance Sheet Arrangements

From time-to-time, we enter into off-balance sheet arrangements and transactions that can give rise to off-balance sheet obligations. As of December 31, 2017, the off-balance sheet arrangements and transactions that we have entered into include undrawn letters of credit and operating lease agreements. We do not believe that these arrangements are reasonably likely to materially affect our liquidity or availability of, or requirements for, capital resources.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Some of the information below contains forward-looking statements. The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term “market risk” refers to the risk of loss arising from adverse changes in oil, NGLs and gas prices, and other related factors. The disclosure is not meant to be a precise indicator of expected future losses, but rather an indicator of reasonably possible losses. This forward-looking information provides an indicator of how we view and manage our ongoing market risk exposures. Our market risk sensitive instruments were entered into for commodity derivative and investment purposes, not for trading purposes.

Proved Reserves

Estimates of proved oil and gas reserves directly impact financial accounting estimates including DD&A, evaluation of impairment of properties and the calculation of plugging and abandonment liabilities. 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. The process of estimating quantities of proved reserves is very complex, requiring significant subjective decisions in the evaluation of all geological, engineering and economic data for each reservoir. The data for any reservoir may change substantially over time due to results from operational activity. Proved reserve volumes at December 31, 2017, were estimated based on the average of the closing price on the first day of each month for the 12-month period prior to December 31, 2017, for oil, NGLs and natural gas in accordance with SEC rules. Changes in commodity prices and operations costs may increase or decrease estimates of proved oil, NGLs and natural gas reserves.

We expect that reductions in oil, NGLs and gas prices will not only decrease our revenues, but will also reduce the amount of oil, NGLs and gas that we can produce economically and therefore lower our oil, NGLs and gas reserves. A decrease of 10% in the oil, NGLs and gas prices used in our reserve report as of December 31, 2017, holding production and development costs constant, would result in:

- a decrease in our PV-10 as of December 31, 2017 of 25%;
- a decrease in our total proved reserves of 28%; and
- a decrease in our proved undeveloped reserves of 43%.

Actual future net revenues and reserve volumes also will be affected by factors such as the amount and timing of actual production, prevailing operating and development costs, supply and demand for oil and gas, increases or decreases in consumption and changes in governmental regulations or taxation. Additionally, depletion expense for our oil and gas properties is determined using our estimates of proved oil, NGLs and natural gas reserves. A hypothetical 10% decline in our December 31, 2017, estimated proved reserves would have increased our depletion expense by approximately $1.8 million for the year ended December 31, 2017.

Commodity Price Risk

Given the current economic outlook, we expect commodity prices to remain volatile. Even modest decreases in commodity prices can materially affect our revenues and cash flow. In addition, if commodity prices remain suppressed for a significant amount of time, we could be required under successful efforts accounting rules to write down our oil and gas properties.

In the year ended December 31, 2017, the NYMEX WTI prompt month price ranged from a low of $42.53 per barrel to a high of $60.42 per barrel. In the year ended December 31, 2016, the NYMEX WTI prompt month price ranged from a low of $26.21 per barrel to a high of $54.06 per barrel.

In the year ended December 31, 2017, the NYMEX Henry Hub natural gas prompt month price ranged from a low of $2.56 per MMBtu to a high of $3.72 per MMBtu. In the year ended December 31, 2016, the NYMEX Henry Hub natural gas prompt month price ranged from a low of $1.64 per MMBtu to a high of $3.93 per MMBtu.

We enter into financial swaps and options to reduce the risk of commodity price fluctuations. We do not designate such instruments as cash flow hedges. Accordingly, we record open commodity derivative positions on our consolidated balance sheets at fair value and recognize changes in such fair values as commodity derivative (loss) gain on our consolidated statements of operations as they occur.

The table below summarizes our commodity derivatives positions outstanding at December 31, 2017.

Commodity and Period	Contract Type	Volume Transacted	Contract Price
Crude Oil			
January 2018 — December 2018	Swap	300 Bbls/day	$50.00/Bbl
January 2018 — March 2018	Collar	1,000 Bbls/day	$50.00/Bbl - $55.05/Bbl
January 2018 — June 2018	Collar	500 Bbls/day	$55.00/Bbl - $60.00/Bbl
Natural Gas			
January 2018 — December 2018	Swap	200,000 MMBtu/month	$3.085/MMBtu
January 2018 — December 2018	Swap	250,000 MMBtu/month	$3.084/MMBtu
NGLs (C3 - Propane)			
January 2018 — March 2018	Swap	450 Bbls/day	$30.24/Bbl
NGLs (IC4 - Isobutane)			
January 2018 — March 2018	Swap	50 Bbls/day	$36.12/Bbl
NGLs (NC4 - Butane)			
January 2018 — March 2018	Swap	150 Bbls/day	$35.70/Bbl

After December 31, 2017, we entered into the following commodity derivative positions:

Commodity and Period	Contract Type	Volume Transacted	Contract Price
Crude Oil			
January 2018 — September 2018	Swap	700 Bbls/day	$60.50/Bbl
April 2018 — September 2018	Swap	800 Bbls/day	$60.50/Bbl
NGLs (C2 - Ethane)			
February 2018 — December 2018	Swap	1,000 Bbls/day	$11.424/Bbl
NGLs (C3 - Propane)			
February 2018 — December 2018	Swap	600 Bbls/day	$32.991/Bbl

NGLs (IC4 - Isobutane)			
February 2018 — December 2018	Swap	50 Bbls/day	$38.262/Bbl
NGLs (NC4 - Butane)			
February 2018 — December 2018	Swap	200 Bbls/day	$38.22/Bbl
NGLs (C5 - Pentane)			
January 2018 — December 2018	Swap	200 Bbls/day	$56.364/Bbl

At December 31, 2017, the fair value of our open derivative contracts was a net liability of approximately $0.8 million, compared to a liability of $4.9 million at December 31, 2016.

We are exposed to credit losses in the event of nonperformance by counterparties on our commodity derivatives positions. We do not anticipate nonperformance by the counterparties over the term of the commodity derivatives positions; however, we cannot be certain that we will not experience such losses in the future. All of the counterparties to our commodity derivative positions are participants in our revolving credit facility, and the collateral for the outstanding borrowings under our revolving credit facility is used as collateral for our commodity derivatives.

Derivative assets and liabilities on our commodity derivative contracts, at fair value, are included on our consolidated balance sheets as current or non-current assets or liabilities based on the anticipated timing of cash settlements under the related contracts. Cash settlements under our commodity derivative contracts and changes in the fair value of our commodity derivative contracts are recorded in earnings as they occur and included in commodity derivative (loss) gain on our consolidated statements of operations. We estimate the fair values of swap or collar contracts based on the present value of the difference in exchange-quoted forward price curves and contractual settlement prices multiplied by notional quantities. We internally valued the option contracts using industry-standard option pricing models and observable market inputs. We use our internal valuations to determine the fair values of the contracts that are reflected on our consolidated balance sheets.

For the years ended December 31, 2017 and 2016 we recognized commodity derivative losses of $0.3 million and $5.5 million, respectively; compared to commodity derivative gains of $19.3 million for the year ended December 31, 2015. A hypothetical 10% increase in the NYMEX floating prices would have resulted in a $3 million decrease in the fair value recorded of our commodity derivative positions on our balance sheet at December 31, 2017, and a corresponding increase to the commodity derivative loss on our statement of operations for the year ended December 31, 2017.

See Note 7 to our consolidated financial statements for a discussion of our fair value measurements.

Interest Rate Risk

We are exposed to interest rate risk on the outstanding borrowings under our revolving credit facility. At December 31, 2017, we had $291 million outstanding under our revolving credit facility. Outstanding borrowings under our revolving credit facility bear interest based on the agent bank's prime rate plus an applicable margin ranging from 2% to 3%, or the sum of the London Interbank Offered Rate ("LIBOR") rate plus an applicable margin ranging from 3% to 4%. Margins vary based on the borrowings outstanding compared to the borrowing base. A hypothetical increase of 50 basis points in the floating interest rate on outstanding borrowings under our revolving credit facility at December 31, 2017, would result in a $1.5 million increase in annual interest expense. We currently do not engage in any interest rate hedging activities.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Our consolidated financial statements and supplemental data are included in this report beginning on page F-1.

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

We had no changes in, and no disagreements with, our accountants on accounting and financial disclosure.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Our management, with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2017. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of December 31, 2017, our disclosure controls and procedures were effective, in that they ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is (1) recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and (2) accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Internal Control over Financial Reporting

Management’s Annual Report on Internal Control Over Financial Reporting and Attestation Report of Registered Public Accounting Firm

Pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, we have included a report of management’s assessment of the design and effectiveness of our internal controls as part of this annual report on Form 10-K for the fiscal year ended December 31, 2017. Moss Adams LLP (“Moss Adams”), our independent registered public accounting firm, also attested to, and reported on, our internal control over financial reporting. Management’s report and Moss Adams’s attestation report are referenced on page F-1 under the captions “Management’s Report on Internal Control over Financial Reporting” and “Report of Independent Registered Public Accounting Firm —Internal Control over Financial Reporting” and are incorporated herein by reference.

Changes in Internal Control over Financial Reporting

No changes to our internal control over financial reporting occurred during the quarter ended December 31, 2017, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act).

ITEM 9B. OTHER INFORMATION
None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information required under Item 10 of this report will be contained under the captions "Election of Directors–Directors," "Executive Officers" and "Corporate Governance" to be provided in our proxy statement for our 2018 annual meeting of stockholders to be filed with the SEC within 120 days of December 31, 2017, which is incorporated herein by reference. Also, the charters of our Audit Committee, Compensation Committee and Nominating and Corporate Governance Committee, our Lead Independent Director Charter, our Governance Guidelines and our Code of Conduct may be found on our website at www.approachresources.com.

ITEM 11. EXECUTIVE COMPENSATION

Information required by Item 11 of this report will be contained under the caption "Executive Compensation" in our definitive proxy statement for our 2018 annual meeting of stockholders to be filed with the SEC within 120 days of December 31, 2017, which is incorporated herein by reference.

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

Information required by Item 12 of this report will be contained under the caption "Stock Ownership Matters" in our definitive proxy statement for our 2018 annual meeting of stockholders to be filed with the SEC within 120 days of December 31, 2017, which is incorporated herein by reference.

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

Information required by Item 13 of this report will be contained under the captions "Certain Relationships and Related-Party Transactions" and "Corporate Governance–Board Independence" in our definitive proxy statement for our 2018 annual meeting of stockholders to be filed with the SEC within 120 days of December 31, 2017, which are incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information required by Item 14 of this report will be contained under the caption "Independent Registered Public Accountants" in our definitive proxy statement for our 2018 annual meeting of stockholders to be filed with the SEC within 120 days of December 31, 2017, which is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) Documents filed as part of this report

(1) and (2) Financial Statements.

See "Index to Consolidated Financial Statements" on page F-1.

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.

(3) Exhibits.

The following documents are filed as exhibits to this report.

Exhibit Number	Exhibit title
3.1	Certificate of Amendment of Restated Certificate of Incorporation of Approach Resources Inc. (filed as Exhibit 3.1 to the Company's Annual Report on Form 10-K filed March 10, 2017, and incorporated herein by reference).
3.2	Restated Certificate of Incorporation of Approach Resources Inc. (filed as Exhibit 3.1 to the Company's Quarterly Report on Form 10-Q filed December 13, 2007, and incorporated herein by reference).
3.3	Second Amended and Restated Bylaws of Approach Resources Inc. (filed as Exhibit 3.2 to the Company's Current Report on Form 8-K filed November 8, 2013, and incorporated herein by reference).
4.1	Specimen Common Stock Certificate (filed as Exhibit 4.1 to the Company's Registration Statement on Form S-1/A filed October 18, 2007 (File No. 333-144512), and incorporated herein by reference).
4.2	Second Supplemental Indenture, dated as of December 20, 2016, by and among Approach Resources Inc., the guarantors named therein and Wilmington Trust, National Association, as successor trustee under the Indenture (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K filed December 22, 2016, and incorporated herein by reference).
4.3	First Supplemental Indenture, dated as of June 11, 2013, among Approach Resources Inc., as issuer, the subsidiary guarantors named therein, as guarantors, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.2 to the Company's Current Report on Form 8-K filed June 11, 2013, and incorporated herein by reference).
4.4	Senior Indenture, dated as of June 11, 2013, among Approach Resources Inc., as issuer, the subsidiary guarantors named therein, as guarantors, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K filed June 11, 2013, and incorporated herein by reference).
4.5	

Agreement dated as of April 28, 2016, by and among Approach Resources, Inc., Wells Fargo Bank, National Association, and Wilmington Trust, National Association (filed as Exhibit 4.4 to the Company's Quarterly Report on Form 10-Q filed August 4, 2016, and incorporated herein by reference).

Exhibit Number	Exhibit title
4.6	Registration Rights Agreement, dated as of January 27, 2017, by and among Approach Resources Inc., Wilks Brothers, LLC and SDW Investments, LLC (filed as Exhibit 4.2 to the Company’s Current Report on Form 8-K filed January 30, 2017, and incorporated herein by reference).
4.7	Registration Rights Agreement, dated as of November 14, 2007, by and among Approach Resources Inc. and investors identified therein (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K/A filed December 3, 2007, and incorporated herein by reference).
*4.8	Registration Rights Agreement, dated as of November 20, 2017, by and among Approach Resources Inc. and Amistad Energy Partners, LLC.
10.1	Form of Amended and Restated Indemnity Agreement between Approach Resources Inc. and each of its directors and officers (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K filed May 7, 2012 (File No. 333-144512), and incorporated herein by reference).
10.2†	Amended and Restated Employment Agreement by and between Approach Resources Inc. and J. Ross Craft dated January 1, 2011 (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K filed January 6, 2011, and incorporated herein by reference).
10.3†	Amendment to Employment Agreement by and between Approach Resources Inc. and J. Curtis Henderson dated January 26, 2017 (filed as Exhibit 10.3 to the Company’s Annual Report on Form 10-K filed March 10, 2017, and incorporated herein by reference).
10.4†	Employment Agreement by and between Approach Resources Inc. and J. Curtis Henderson dated January 1, 2011 (filed as Exhibit 10.3 to the Company’s Current Report on Form 8-K filed January 6, 2011, and incorporated herein by reference).
10.5†	Amendment to Employment Agreement by and between Approach Resources Inc. and Qingming Yang dated January 26, 2017 (filed as Exhibit 10.5 to the Company’s Annual Report on Form 10-K filed March 10, 2017, and incorporated herein by reference).
10.6†	Employment Agreement by and between Approach Resources Inc. and Qingming Yang dated January 24, 2011 (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K filed January 28, 2011, and incorporated herein by reference).
10.7†	Employment Agreement by and between Approach Resources Inc., and Sergei Krylov dated January 3, 2014 (filed as Exhibit 10.1 to the Company’s Quarterly Report on Form 10-Q filed May 9, 2014, and incorporated herein by reference).
10.8	Form of Business Opportunities Agreement among Approach Resources Inc. and the other signatories thereto (filed as Exhibit 10.11 to the Company’s Registration Statement on Form S-1/A filed October 18, 2007 (File No. 333-144512), and incorporated herein by reference).
10.9†	Sixth Amendment to the Approach Resources Inc. 2007 Stock Incentive Plan effective as of June 7, 2017 (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K filed June 7, 2017, and incorporated herein by reference).

10.10†	Fifth Amendment to the Approach Resources Inc. 2007 Stock Incentive Plan effective as of June 2, 2016 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed June 2, 2016, and incorporated herein by reference).

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Exhibit Number	Exhibit title
10.11†	Fourth Amendment to the Approach Resources Inc. 2007 Stock Incentive Plan (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q filed May 5, 2016, and incorporated herein by reference).
10.12†	Third Amendment to the Approach Resources Inc. 2007 Stock Incentive Plan (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed June 2, 2015, and incorporated herein by reference).
10.13†	Second Amendment to the Approach Resources Inc. 2007 Stock Incentive Plan, effective as of May 31, 2012 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed June 1, 2012, and incorporated herein by reference).
10.14†	First Amendment dated December 31, 2008, to Approach Resources Inc. 2007 Stock Incentive Plan, effective as of June 28, 2007 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed December 31, 2008, and incorporated herein by reference).
10.15†	Approach Resources Inc. 2007 Stock Incentive Plan, effective as of June 28, 2007 (filed as Exhibit 10.6 to the Company's Registration Statement on Form S-1 filed July 12, 2007, and incorporated herein by reference).
10.16†	Form of Restricted Stock Award Agreement under Approach Resources Inc. 2007 Stock Incentive Plan (filed as Exhibit 10.10 to the Company's Quarterly Report on Form 10-Q filed November 6, 2008, and incorporated herein by reference).
10.17†	Form of Performance-Based, Time-Vesting Restricted Stock Award Agreement under Approach Resources Inc. 2007 Stock Incentive Plan (filed as Exhibit 10.14 to the Company's Annual Report on Form 10-K filed March 11, 2011, and incorporated herein by reference).
10.18†	Revised Form of TSR-Based Restricted Stock Award Agreement under Approach Resources Inc. 2007 Stock Incentive Plan (filed as Exhibit 10.17 to the Company's Annual Report on Form 10-K filed March 10, 2017, and incorporated herein by reference).
10.19†	Form of TSR-Based Restricted Stock Award Agreement under Approach Resources Inc. 2007 Stock Incentive Plan (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed February 20, 2012, and incorporated herein by reference).
10.20†	Form of Cash Settled Performance Share Unit Award Agreement under Approach Resources Inc. 2007 Stock Incentive Plan (filed as Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q filed May 5, 2016, and incorporated herein by reference).
10.21	Exchange Agreement, dated as of November 2, 2016, by and among Approach Resources Inc., Wilks Brothers, LLC and SDW Investments, LLC (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed November 3, 2016, and incorporated herein by reference).
10.22	Stockholder Agreement, dated as of January 27, 2017, by and among Approach Resources Inc., Wilks Brothers, LLC and SDW Investments, LLC (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed January 30, 2017, and incorporated herein by reference).

Exhibit Number	Exhibit title
10.23	Amendment dated August 4, 2014 to Gas Purchase Contract dated as of January 1, 2011, between Approach Resources I, LP and Approach Oil & Gas Inc., as Seller, and DCP Midstream, LP, as Buyer (pursuant to a request for confidential treatment, portions of this exhibit have been redacted and have been provided separately to the Securities and Exchange Commission) (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q filed November 6, 2014, and incorporated herein by reference).
10.24	Gas Purchase Contract dated as of January 1, 2011, between Approach Resources I, LP and Approach Oil & Gas Inc., as Seller, and DCP Midstream, LP, as Buyer (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed January 14, 2011, and incorporated herein by reference).
10.25	Specimen Oil and Gas Lease for University Lands (filed as Exhibit 10.19 to the Company's Annual Report on Form 10-K filed March 12, 2012, and incorporated herein by reference).
10.26	Fourth Amendment dated as of December 21, 2017, to Amended and Restated Credit Agreement dated as of May 7, 2014, by and among the Company and its subsidiary guarantors, JPMorgan Chase Bank, N.A., as Administrative Agent, and each of the lenders party thereto (files as Exhibit 10.1 to the Company's Current Report on Form 8-K filed December 26, 2017, and incorporated herein by reference).
10.27	Third Amendment dated as of May 3, 2016, to Amended and Restated Credit Agreement dated as of May 7, 2014, by and amount the Company, JPMorgan Chase Bank, N.A., as Administrative Agent, and each of the Lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed May 4, 2016, and incorporated herein by reference).
10.28	Second Amendment dated as of December 30, 2014, to Amended and Restated Credit Agreement, dated as of May 7, 2014, by and among the Company, JPMorgan Chase Bank, N.A., as Administrative Agent, and each of the Lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed January 6, 2015, and incorporated herein by reference).
10.29	First Amendment dated as of November 4, 2014, to Amended and Restated Credit Agreement, dated as of May 7, 2014, by and among the Company, JPMorgan Chase Bank, N.A., as Administrative Agent, and each of the Lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed November 5, 2014, and incorporated herein by reference).
10.30	Amended and Restated Credit Agreement, dated as of May 7, 2014, by and among the Company, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders from time-to-time party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed May 8, 2014, and incorporated herein by reference).
10.31	Amended and Restated Guaranty and Pledge Agreement, dated as of May 7, 2014, by and among the Company, the subsidiary guarantors and JPMorgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K filed May 8, 2014, and incorporated herein by reference).
10.32	Amendment No. 1 to Crude Oil Purchase Agreement dated as of October 7, 2013, between Approach Operating, LLC, Approach Oil & Gas Inc. and Approach Resources I, LP, and Wildcat Permian Services LLC and JP Energy Development, LP (pursuant to a request for confidential treatment, portions of this

exhibit have been redacted and have been provided separately to the Securities and Exchange Commission) (filed as Exhibit 10.37 to the Company's Annual Report on Form 10-K filed February 25, 2014, and incorporated herein by reference).

Exhibit Number	Exhibit title
10.33	Crude Oil Purchase Agreement dated as of September 12, 2012, between Approach Operating, LLC and Approach Oil & Gas Inc., as Seller, and Wildcat Permian Services LLC, as Buyer (pursuant to a request for confidential treatment, portions of this exhibit have been redacted and have been provided separately to the Securities and Exchange Commission) (filed as Exhibit 10.4 of the Company's Quarterly Report on Form 10-Q filed or November 6, 2012, and incorporated herein by reference).
*12.1	Statement of Computation Ratio of Earnings to Fixed Charges.
14.1	Code of Conduct (filed as Exhibit 14.1 to the Company's Annual Report on Form 10-K filed March 28, 2008, and incorporated herein by reference).
*21.1	Subsidiaries.
*23.1	Consent of Moss Adams LLP.
*23.2	Consent of Hein & Associates LLP.
*23.3	Consent of DeGolyer and MacNaughton.
*31.1	Certification by the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification by the Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification by the Chief Financial Officer Pursuant to U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*99.1	Report of DeGolyer and MacNaughton.
*101.INS	XBRL Instance Document.
*101.SCH	XBRL Taxonomy Extension Schema Document.
*101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
*101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
*101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.
*101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.

* Filed herewith.
† Denotes management contract or compensatory plan or arrangement.

ITEM 16. FORM 10-K SUMMARY

None.

GLOSSARY AND SELECTED ABBREVIATIONS

The following is a description of the meanings of some of the oil and gas industry terms used in this report.

3-D seismic	(Three Dimensional Seismic Data) Geophysical data that depicts the subsurface strata in three dimensions. 3-D seismic data typically provides a more detailed and accurate interpretation of the subsurface strata than two dimensional seismic data.
Basin	A large natural depression on the earth's surface in which sediments generally brought by water accumulate.
Bbl	One stock tank barrel, of 42 U.S. gallons liquid volume, used to reference oil, condensate or NGLs.
Boe	Barrel of oil equivalent, determined using the ratio of six Mcf of gas to one Boe, and one Bbl of NGLs to one Boe.
Btu or British Thermal Unit	The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.
Completion	The installation of permanent equipment for production of oil or gas, or, in the case of a dry well, for reporting to the appropriate authority that the well has been abandoned.
Developed acreage	The number of acres that are allocated or assignable to productive wells or wells that are capable of production.
Developed oil and gas reserves	

	Has the meaning given to such term in Rule 4-10(a)(6) of Regulation S-X, as follows: 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.
Development project	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.
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.
Dry hole or well	An exploratory, development or extension well that proved to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.
Dry hole costs	Costs incurred in drilling a well, assuming a well is not successful, including plugging and abandonment costs.
Exploratory well	A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir.
Extension well	A well drilled to extend the limits of a known reservoir.

Farm-in	An arrangement in which the owner or lessee of mineral rights (the first party) assigns a working interest to an operator (the second party), the consideration for which is specified exploration and/or development activities. The first party retains an overriding royalty, working interest or other type of economic interest in the mineral production. The arrangement from the viewpoint of the second party is termed a “farm-in” arrangement.
Field	An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.
Field fuel	Gas consumed to operate field

	equipment (primarily for compressors and artificial lifts).
Hydraulic fracturing	The technique designed to improve a well's production rates by pumping a mixture of water and sand (in our case, over 99% by mass) and chemical additives (in our case, less than 1% by mass) into the formation and rupturing the rock, creating an artificial channel.
Henry Hub	Henry Hub is the major exchange for pricing for natural gas futures on the NYMEX.
Gross acres or gross wells	The total acres or wells, as the case may be, in which a working interest is owned.
Lease operating expenses	The expenses of lifting oil or gas from a producing formation to the surface, and the transportation and marketing thereof, constituting part of the current operating expenses of a working interest, and also including labor,

	superintendence, supplies, repairs, short-lived assets, maintenance, allocated overhead costs and other expenses incidental to production, but excluding lease acquisition or drilling or completion expenses.
LNG	Liquefied natural gas.
MBbls	Thousand barrels of oil or other liquid hydrocarbons.
MBoe	Thousand barrels of oil equivalent, determined using the ratio of six Mcf of gas to one Boe, and one Bbl of NGLs to one Boe.
Mcf	Thousand cubic feet of natural gas.
MMBoe	Million barrels of oil equivalent, determined using the ratio of six Mcf of gas to one Boe, and one Bbl of NGLs to one Boe.
MMBtu	Million British thermal units.
MMcf	

	Million cubic feet of gas.
Net acres or net wells	The sum of the fractional working interests owned in gross acres or wells, as the case may be.
NGLs	Natural gas liquids. The portions of gas from a reservoir that are liquefied at the surface in separators, field facilities or gas processing plants.
NYMEX	New York Mercantile Exchange.
Play	A set of known or postulated oil and/or gas accumulations sharing similar geologic, geographic and temporal properties, such as source rock, migration pathways, timing, trapping mechanism and hydrocarbon type.
Productive well	An exploratory, development or extension well that is not a dry well.

Prospect	A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.
Proved developed producing reserves	Proved developed oil and gas reserves that are 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.
Proved oil and gas reserves	Has the meaning given to such term in Rule 4-10(a)(22) of Regulation S-X, as follows:
	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.
PV-10	An estimate of the present value of the future net revenues from proved oil and gas reserves after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates of federal income taxes. The estimated future net revenues are discounted at an annual rate of 10% to determine their "present value." The present value is shown to indicate the effect of time on the value of the revenue stream and should not be construed as being the fair market value of the properties. Estimates of PV-10 are made using oil and gas prices and operating costs at the date indicated and held constant for the life of the reserves.
"Recompletion" or to "recomplete" a well	The addition of production from another interval or formation in an existing wellbore.
Reserve life	This index is calculated by dividing year-end 2017 estimated proved reserves by 2017 production of 4.2 MMBoe to estimate the number of years of remaining production.
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.
Spacing	The distance between wells producing from the same reservoir. Spacing is expressed in terms of acres (e.g., 40-acre spacing) and is established by regulatory agencies.
Standardized measure	The present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC (using prices and costs in effect as of the period end date) without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depletion, depreciation and amortization and discounted using an annual discount rate of 10%. Standardized measure does not give effect to derivative transactions.
Tight gas sands	A sandstone formation with low permeability that produces natural gas with low flow rates for long periods of time.
Unconventional resources or reserves	Natural gas or oil resources or reserves from (i) low-permeability sandstone and shale formations and (ii) coalbed methane.
Undeveloped acreage	Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or gas regardless of whether such

	acreage contains proved reserves.
Undeveloped oil and gas reserves	Has the meaning given to such term in Rule 4-10(a)(31) of Regulation S-X, which defines proved undeveloped reserves as follows:

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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, an analogous reservoir or by other evidence using reliable technology establishing reasonable certainty.
Working interest	The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production.	
Workover	Operations on a producing well to restore or increase production.	

WTI	West Texas Intermediate, a grade of crude oil used as a benchmark in oil pricing.
/d	“Per day” when used with volumetric units or dollars.

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.

APPROACH RESOURCES INC.

By: /s/ J. Ross Craft
J. Ross Craft
Chairman of the Board and Chief Executive Officer

Date: March 9, 2018

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 indicated and on March 9, 2018.

Signature	Title
/s/ J. Ross Craft J. Ross Craft	Chairman of the Board and Chief Executive Officer, (Principal Executive Officer)
/s/ Sergei Krylov Sergei Krylov	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ Ian M. Shaw Ian M. Shaw	Chief Accounting Officer, (Principal Accounting Officer)
/s/ Vean J. Gregg III Vean J. Gregg III	Lead Independent Director
/s/ Alan D. Bell Alan D. Bell	Director
/s/ James C. Crain James C. Crain	Director
/s/ Matthew R. Kahn Matthew R. Kahn	Director
/s/ Morgan D. Neff Morgan D. Neff	Director
/s/ Matthew D. Wilks Matthew D. Wilks	Director

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS OF APPROACH RESOURCES INC.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). Our internal control over financial reporting is designed to provide reasonable assurance to management and our board of directors regarding the preparation and fair presentation of published financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2017. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control —Integrated Framework in 2013. Based on our assessment, we believe that, as of December 31, 2017, our internal control over financial reporting is effective based on those criteria.

Moss Adams LLP, the independent registered public accounting firm that audited our financial statements included in this annual report, has issued an attestation report on our internal control over financial reporting as of December 31, 2017. This report appears on the following page.

By:	/s/ J. Ross Craft	By:	/s/ Sergei Krylov
	J. Ross Craft		Sergei Krylov
	Chairman of the Board and Chief Executive Officer		Executive Vice President and Chief Financial Officer

Fort Worth, Texas

March 9, 2018

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders

Approach Resources Inc.

Opinion on Internal Control over Financial Reporting

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

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated balance sheet of Approach Resources Inc. and subsidiaries as of December 31, 2017, the related consolidated statements of operations, stockholders' equity, and cash flows for the year ended December 31, 2017, and the related notes (collectively referred to as the "consolidated financial statements") and our report dated March 9, 2018 expressed an unqualified opinion on those consolidated financial statements.

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 included in Item 9A. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included 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/ Moss Adams LLP
Dallas, Texas
March 9, 2018

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders

Approach Resources Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheet of Approach Resources Inc. and subsidiaries (the "Company") as of December 31, 2017, the related consolidated statement of operations, stockholders' equity, and cash flows for the year ended December 31, 2017, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as of December 31, 2017, and the consolidated results of its operations and its cash flows for the year ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control – Integrated Framework 2013 issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 9, 2018 expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

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

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

/s/ Moss Adams LLP
Dallas, Texas
March 9, 2018

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders

Approach Resources Inc.

We have audited the accompanying consolidated balance sheet of Approach Resources Inc. and subsidiaries (collectively, the “Company”) as of December 31, 2016, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the two years in the period ended December 31, 2016. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Approach Resources Inc. and subsidiaries as of December 31, 2016, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2016, in conformity with U.S. generally accepted accounting principles.

/s/ Hein & Associates LLP
Dallas, Texas
March 10, 2017

Approach Resources Inc. and Subsidiaries

Consolidated Balance Sheets

(In thousands, except shares and per-share amounts)

	December 31, 2017	December 31, 2016
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$21	$21
Accounts receivable:		
Joint interest owners	117	92
Oil, NGLs and gas sales	9,678	9,547
Derivative assets	1,398	—
Prepaid expenses and other current assets	5,486	2,834
Total current assets	16,700	12,494
PROPERTIES AND EQUIPMENT:		
Oil and gas properties, at cost, using the successful efforts method of accounting	1,930,577	1,869,774
Furniture, fixtures and equipment	5,658	5,644
Total oil and gas properties and equipment	1,936,235	1,875,418
Less accumulated depletion, depreciation and amortization	(853,359)	(783,357)
Net oil and gas properties and equipment	1,082,876	1,092,061
Total assets	$1,099,576	$1,104,555
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$9,450	$9,482
Oil, NGLs and gas sales payable	5,363	4,190
Derivative liabilities	2,181	4,880
Accrued liabilities	8,073	7,817
Total current liabilities	25,067	26,369
NON-CURRENT LIABILITIES:		
Senior secured credit facility, net	289,275	271,696
Senior notes, net	84,185	226,653
Deferred income taxes	82,102	5,615
Asset retirement obligations	11,065	10,607
Other non-current liabilities	466	663
Total liabilities	492,160	541,603
COMMITMENTS AND CONTINGENCIES (Note 8)		
STOCKHOLDERS' EQUITY :		
Preferred stock, $0.01 par value, 10,000,000 shares authorized none outstanding	—	—
Common stock, $0.01 par value, 180,000,000 and 90,000,000 shares	945	418

authorized, 94,533,246 and 41,764,770 issued and outstanding, respectively		
Additional paid-in capital	742,391	586,095
Accumulated deficit	(135,920)	(23,561)
Total stockholders’ equity	607,416	562,952
Total liabilities and stockholders’ equity	$1,099,576	$1,104,555

See accompanying notes to these consolidated financial statements.

Approach Resources Inc. and Subsidiaries

Consolidated Statements of Operations

(In thousands, except shares and per-share amounts)

	Years Ended December 31,		
	2017	2016	2015
REVENUES:			
Oil, NGLs and gas sales	$105,349	$90,302	$131,336
EXPENSES:			
Lease operating	17,902	19,250	28,972
Production and ad valorem taxes	8,644	8,217	11,085
Exploration	3,657	3,923	4,439
General and administrative(1)	24,333	24,734	28,341
Termination costs	—	—	1,436
Impairment of oil and gas properties	—	—	220,197
Depletion, depreciation and amortization	70,521	79,044	109,319
Total expenses	125,057	135,168	403,789
OPERATING LOSS	(19,708)	(44,866)	(272,453)
OTHER:			
Interest expense, net	(21,053)	(27,259)	(25,066)
Gain on debt extinguishment	5,053	—	10,563
Write-off of debt issuance costs	—	(563)	—
Commodity derivative (loss) gain	(262)	(5,484)	19,275
Other income	32	1,511	172
LOSS BEFORE INCOME TAX PROVISON (BENEFIT)	(35,938)	(76,661)	(267,509)
INCOME TAX PROVISON (BENEFIT):			
Current	(66)	—	(265)
Deferred	76,487	(24,418)	(93,140)
NET LOSS	$(112,359)	$(52,243)	$(174,104)
LOSS PER SHARE:			
Basic	$(1.35)	$(1.26)	$(4.30)
Diluted	$(1.35)	$(1.26)	$(4.30)
WEIGHTED AVERAGE SHARES OUTSTANDING:			
Basic	83,404,104	41,488,206	40,464,283
Diluted	83,404,104	41,488,206	40,464,283
(1) Includes non-cash share-based compensation expense as follows:	4,656	6,279	7,954

See accompanying notes to these consolidated financial statements.

Approach Resources Inc. and Subsidiaries

Consolidated Statements of Changes in Stockholders' Equity

for the Years Ended December 31, 2015, 2016 and 2017

(In thousands, except shares and per-share amounts)

	Common Stock		Additional Paid-in Capital	Accumulated (Deficit) Earnings	Total
	Shares	Amount			
BALANCES, January 1, 2015	39,814,199	$ 399	$ 572,888	$ 201,040	$ 774,327
Issuance of common shares to directors for compensation	134,783	1	734	—	735
Restricted stock issuance, net of cancellations	897,285	8	(8)	—	—
Share-based compensation expense	—	—	7,219	—	7,219
Surrender of restricted shares for payment of income taxes	(57,562)	—	(210)	—	(210)
Net income	—	—	—	(174,104)	(174,104)
BALANCES, December 31, 2015	40,788,705	$ 408	$ 580,623	$ 26,936	$ 607,967
Cumulative effect of change in accounting principal	—	$ —	$ —	$ 1,746	$ 1,746
Issuance of common shares to directors for compensation	196,287	2	212	—	214
Restricted stock issuance, net of cancellations	1,013,982	10	(10)	—	—
Share-based compensation expense	—	—	6,065	—	6,065
Surrender of restricted shares for payment of income taxes	(234,204)	(2)	(795)	—	(797)
Net loss	—	—	—	(52,243)	(52,243)
BALANCES, December 31, 2016	41,764,770	$ 418	$ 586,095	$ (23,561)	$ 562,952
Issuance of common shares to directors for compensation	179,255	$ 1	$ 448	$ —	$ 449
Restricted stock issuance, net of cancellations	2,074,539	20	(20)	—	—
Share-based compensation expense	—	—	4,207	—	4,207
Surrender of restricted shares for payment of income taxes	(234,049)	(2)	(649)	—	(651)
Issuance of common shares in exchange for senior notes	43,175,328	432	134,526	—	134,958
Issuance of common shares for acquisition	7,573,403	76	17,784	—	17,860

Net loss	—	—	—	(112,359)	(112,359)
BALANCES, December 31, 2017	94,533,246	$ 945	$ 742,391	$ (135,920)	$ 607,416

See accompanying notes to these consolidated financial statements.

Approach Resources Inc. and Subsidiaries

Consolidated Statements of Cash Flows

(In thousands, except shares and per-share amounts)

	For the Years Ended December 31,		
	2017	2016	2015
OPERATING ACTIVITIES:			
Net loss	$(112,359)	$(52,243)	$(174,104)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depletion, depreciation and amortization	70,521	79,044	109,319
Impairment of oil and gas properties	—	—	220,197
Amortization of debt issuance costs	866	1,396	1,561
Gain on debt extinguishment	(5,053)	—	(10,563)
Write-off of debt issuance costs	—	563	—
Commodity derivative loss (gain)	262	5,484	(19,275)
Settlements of commodity derivatives	(4,359)	6,132	52,489
Exploration expense	3,522	3,753	1,836
Share-based compensation expense	4,656	6,279	7,954
Deferred income tax (benefit) expense	76,487	(24,418)	(93,140)
Other non-cash items	(32)	(92)	(172)
Changes in operating assets and liabilities:			
Accounts receivable	400	2,250	7,878
Prepaid expenses and other current assets	83	534	(325)
Accounts payable	907	358	964
Oil, NGLs and gas sales payable	919	(55)	(4,291)
Accrued liabilities	634	(2,904)	2,388
Cash provided by operating activities	37,454	26,081	102,716
INVESTING ACTIVITIES:			
Additions to oil and gas properties	(47,051)	(19,788)	(151,178)
Additions to furniture, fixtures and equipment, net	(14)	(16)	(67)
Change in working capital related to investing activities	(5,344)	(4,086)	(66,102)
Cash used in investing activities	(52,409)	(23,890)	(217,347)
FINANCING ACTIVITIES:			
Borrowings under credit facility	111,250	50,100	272,000
Repayment of amounts outstanding under credit facility	(93,250)	(50,100)	(149,000)
Extinguishment of senior notes	—	—	(8,722)
Tax withholdings related to restricted stock	(650)	(797)	(210)
Equity issuance costs	(2,780)	—	—
Debt issuance costs	(977)	(197)	—
Change in working capital related to financing activities	1,362	(1,776)	731
Cash (used in) provided by financing activities	14,955	(2,770)	114,799
CHANGE IN CASH AND CASH EQUIVALENTS	—	(579)	168

CASH AND CASH EQUIVALENTS , beginning of year	21	600	432
CASH AND CASH EQUIVALENTS , end of year	$21	$21	$600
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash paid for income taxes	$—	$—	$—
Cash paid for interest	$20,584	$25,972	$23,634
SUPPLEMENTAL DISCLOSURE OF NON-CASH TRANSACTION:			
Asset retirement obligations capitalized	$39	$36	$151

See accompanying notes to these consolidated financial statements.

Approach Resources Inc. and Subsidiaries

Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies
Organization and Nature of Operations

Approach Resources Inc. ("Approach," the "Company," "we," "us" or "our") is an independent energy company focused on the exploration, development, production and acquisition of unconventional oil and gas properties. We focus on finding and developing oil and natural gas reserves in oil shale and tight gas sands. Our properties are primarily located in the Permian Basin in West Texas. We also own interests in the East Texas Basin.

Consolidation, Basis of Presentation and Significant Estimates

The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America and include the accounts of the Company and its wholly owned subsidiaries. Intercompany accounts and transactions are eliminated. In preparing the accompanying financial statements, management has made certain estimates and assumptions that affect reported amounts in the financial statements and disclosures of contingencies. Actual results may differ from those estimates. Significant assumptions are required in the valuation of proved oil and natural gas reserves, which affect our estimate of depletion expense as well as our impairment analyses. Significant assumptions also are required in our estimation of accrued liabilities, commodity derivatives, income tax provision, share-based compensation and asset retirement obligations. It is at least reasonably possible these estimates could be revised in the near term, and these revisions could be material. Certain prior-year amounts have been reclassified to conform to current-year presentation. These classifications have no impact on the net loss reported.

Cash and Cash Equivalents

We consider all highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents. At times, the amount of cash and cash equivalents on deposit in financial institutions exceeds federally insured limits. We monitor the soundness of the financial institutions and believe the Company's risk is negligible.

Oil and Gas Properties

Capitalized Costs. Our oil and gas properties comprised the following (in thousands):

	December 31,	
	2017	2016
Mineral interests in properties:		
Unproved leasehold costs	$28,737	$33,596
Proved leasehold costs	60,077	44,643
Wells and related equipment and facilities	1,819,836	1,774,314
Support equipment	8,459	8,002
Uncompleted wells, equipment and facilities	13,468	9,219
Total costs	1,930,577	1,869,774

Less accumulated depreciation, depletion and amortization	(850,301)	(780,412)
Net capitalized costs	$1,080,276	$1,089,362

We follow the successful efforts method of accounting for our oil and gas producing activities. Costs to acquire mineral interests in oil and gas properties and to drill and equip development wells and related asset retirement costs are capitalized. Costs to drill exploratory wells are capitalized pending determination of whether the wells have proved reserves. If we determine that the wells do not have proved reserves, the costs are charged to exploration expense. There were no exploratory wells capitalized, pending determination of whether the wells have proved reserves, at December 31, 2017 or 2016. Geological and geophysical costs, including seismic studies are charged to exploration expense as incurred. We capitalize interest on expenditures for significant exploration and development projects that last more than six months while activities are in progress to bring the assets to their intended use and while these expenditures are excluded from our depletable base. Through December 31, 2017, we have capitalized no interest costs because our individual wells and infrastructure projects are generally developed in less than six months. Costs incurred to maintain wells and related equipment are charged to expense as incurred.

On the sale or retirement of a complete unit of a proved property, the cost and related accumulated depreciation, depletion and amortization are eliminated from the property accounts, and the resulting gain or loss is recognized. On the retirement or sale of a partial unit of proved property, the cost is charged to accumulated depreciation, depletion and amortization with no gain or loss recognized in income.

Capitalized amounts attributable to proved oil and gas properties are depleted by the unit-of-production method over proved reserves using the unit conversion ratio of six Mcf of gas to one barrel of oil equivalent (“Boe”), and one barrel of NGLs to one Boe. The ratios of six Mcf of natural gas to one Boe and one barrel of NGLs to one Boe do not assume price equivalency and, given price differentials, the price for a Boe for natural gas may differ significantly from the price for a barrel of oil. Depreciation, depletion and amortization expense for oil and gas producing property and related equipment was $70.3 million, $78.7 million and $108.8 million for the years ended December 31, 2017, 2016 and 2015, respectively.

Capitalized costs related to proved oil and gas properties, including wells and related equipment and facilities, are periodically evaluated for impairment based on an analysis of undiscounted future net cash flows in accordance with ASC 360, Accounting for the Impairment or Disposal of Long-Lived Assets, as events or changes in circumstances indicate that the carrying values of those assets may not be recoverable. If undiscounted cash flows are insufficient to recover the net capitalized costs related to proved properties, then we recognize an impairment charge equal to the difference between the net capitalized costs related to proved properties and their estimated fair values based on the present value of the related future net cash flows. Estimating future net cash flows involves the use of judgments, including estimation of the proved and unproved oil and natural gas reserve quantities, timing of development and production, expected future commodity prices, capital expenditures and production costs. We recorded no impairment of our proved properties for the years ended December 31, 2017 and 2016. During the year ended December 31, 2015, we recognized an impairment loss of $214.7 million related primarily to our vertical Canyon wells. See Note 7 for proved property impairment disclosures.

Unproved oil and gas properties that are individually significant are periodically assessed for impairment of value, and a loss is recognized at the time of impairment by providing an impairment allowance. We recorded no impairment of our unproved properties for the years ended December 31, 2017 and 2016. Certain leases that we consider non-core to our development of Project Pangea were impaired during the year ended December 31, 2015, as we did not plan to develop them. As a result, we recorded a non-cash impairment loss of unproved property of $5.5 million for the year ended December 31, 2015.

The total impairment loss of $220.2 million for the year ended December 31, 2015, is recorded in impairment of oil and gas properties on our consolidated statements of operations, and in accumulated depletion, depreciation and amortization on our consolidated balance sheets.

On the sale of an entire interest in an unproved property for cash or cash equivalents, gain or loss on the sale is recognized, taking into consideration the amount of any recorded impairment if the property had been assessed individually. If a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained.

Approach Resources Inc. and Subsidiaries

Notes to Consolidated Financial Statements — (Continued)

Other Property

Furniture, fixtures and equipment are carried at cost. Depreciation of furniture, fixtures and equipment is provided using the straight-line method over estimated useful lives ranging from three to 15 years. Gain or loss on retirement or sale or other disposition of assets is included in income in the period of disposition. Depreciation expense for other property and equipment was $237,000, $343,000 and $563,000 for the years ended December 31, 2017, 2016 and 2015, respectively.

Financial Instruments

The carrying amounts of financial instruments including cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities approximate fair value, as of December 31, 2017 and 2016. See Note 7 for fair value disclosures.

Income Taxes

We are subject to U.S. federal income taxes along with state income taxes in Texas. When tax returns are filed, it is highly certain that some positions taken would be sustained upon examination by the taxing authorities, while others are subject to uncertainty about the merits of the position taken or the amount of the position that would be ultimately sustained. The benefit of a tax position is recognized in the financial statements in the period during which, based on all available evidence, management believes it is more likely than not that the position will be sustained upon examination, including the resolution of appeals or litigation processes, if any. Tax positions taken are not offset or aggregated with other positions. Tax positions that meet the more-likely-than-not recognition threshold are measured as the largest amount of tax benefit that is more than 50% likely of being realized upon settlement with the applicable taxing authority. The portion of the benefits associated with tax positions taken that exceeds the amount measured as described above is reflected as a liability for unrecognized tax benefits in the accompanying balance sheet along with any associated interest and penalties that would be payable to the taxing authorities upon examination. Interest and penalties associated with unrecognized tax benefits are classified as additional income taxes on the consolidated statements of operations.

Based on our analysis, we did not have any uncertain tax positions as of December 31, 2017 or 2016. The Company’s income tax returns are subject to examination by the relevant taxing authorities as follows: U.S. Federal income tax returns for tax years 2014 and forward and Texas income and margin tax returns for tax years 2014 and forward. There are currently no income tax examinations underway for these jurisdictions.

Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to the differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using the tax rate in effect for the year in which those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the year of the enacted tax rate change.

We monitor our deferred tax assets by jurisdiction to assess their potential realization, and a valuation allowance is recognized on deferred tax assets when we believe that certain of these assets are more likely than not to be realized. In performing this review, we make estimates and assumptions regarding projected future taxable income, the expected timing of reversals of existing temporary differences and the implementation of tax planning strategies. To the extent that a valuation allowance is established or changed during any period, we would recognize expense or benefit within our consolidated tax expense. We currently have a valuation allowance of $0.5 million on our deferred tax assets, after accounting for the change in the corporate federal income tax rate under the Tax Cuts and Jobs Act.

Derivative Activity

We record our open derivative instruments at fair value on our consolidated balance sheets as either derivative assets or liabilities. Cash settlements and changes in the fair value of our commodity derivative contracts are recorded in earnings as they occur on our consolidated statements of operations under the caption entitled “commodity derivative (loss) gain.”

Approach Resources Inc. and Subsidiaries

Notes to Consolidated Financial Statements — (Continued)

We have not historically designated our derivative instruments as cash-flow hedges; however we use those instruments to reduce our exposure to fluctuations in commodity prices related to our natural gas and oil production. Derivative assets and derivative liabilities, at fair value, are included on our consolidated balance sheets as current or non-current assets or liabilities based on the anticipated timing of cash settlements under the related contracts.

Prepaid Expenses and Other Assets

In April 2017, we entered into an agreement that secured pricing and availability of a dedicated hydraulic fracturing services crew. Under this agreement, we made a prepayment of $5 million, to be used as we completed wells. We have used $0.7 million of this prepayment related to hydraulic fracturing services provided during the first year of the agreement. As of December 31, 2017, we maintained an unused prepaid balance of $4.3 million in prepaid expenses and other current assets on our consolidated balance sheets related to this agreement. After December 31, 2017, we used an additional $0.5 million of this prepayment and $3.8 million of the unused prepaid balance was refunded to us.

Accrued Liabilities

The following is a summary of our accrued liabilities at December 31, 2017 and 2016 (in thousands):

	2017	2016
Capital expenditures accrual	$1,522	$1,067
Operating expenses and other	6,551	6,750
Total	$8,073	$7,817

Asset Retirement Obligations

Our asset retirement obligations relate to future plugging and abandonment expenses on oil and gas properties. Based on the expected timing of payments, the full asset retirement obligation is classified as non-current. There were no significant changes to the asset retirement obligations for the years ended December 31, 2017, 2016 and 2015.

Share-Based Compensation

We measure and record compensation expense for share-based payment awards to employees and outside directors based on estimated grant date fair values. We recognize compensation costs for awards granted over the requisite service period based on the grant date fair value in general and administrative expenses on our consolidated statements of operations. Additionally, we recognize forfeitures of share-based compensation as they occur.

In 2016, we awarded cash-settled performance awards, subject to certain performance conditions, to our executive officers. The cash-settled performance awards represent a non-equity unit with a conversion value equal to the fair market value of a share of the Company’s common stock at the vesting date. These awards are classified as liability awards due to the cash settlement feature. Compensation costs associated with the cash-settled performance awards are re-measured at each interim reporting period and an adjustment is recorded in general and administrative expenses on our consolidated statements of operations.

Approach Resources Inc. and Subsidiaries

Notes to Consolidated Financial Statements — (Continued)

Earnings Per Common Share

We report basic earnings per common share, which excludes the effect of potentially dilutive securities, and diluted earnings per common share, which includes the effect of all potentially dilutive securities unless their impact is antidilutive. The following are reconciliations of the numerators and denominators of our basic and diluted earnings per share, (dollars in thousands, except per-share amounts):

	For the Years Ended December 31,		
	2017	2016	2015
Income (numerator):			
Net (loss) income — basic	$(112,359)	$(52,243)	$(174,104)
Weighted average shares (denominator):			
Weighted average shares — basic	83,404,104	41,488,206	40,464,283
Dilution effect of share-based compensation, treasury method (1)	—	—	—
Weighted average shares — diluted	83,404,104	41,488,206	40,464,283
Net (loss) income per share:			
Basic	$(1.35)	$(1.26)	$(4.30)
Diluted	$(1.35)	$(1.26)	$(4.30)

(1) Approximately 39,000 options to purchase our common stock were excluded from this calculation because they were antidilutive for the years ended December 31, 2016 and 2015. No options were outstanding as of December 31, 2017, as they had expired.

Oil and Gas Operations

Revenue and Accounts Receivable. We recognize revenue for our production when the quantities are delivered to or collected by the respective purchaser. Prices for such production are defined in sales contracts and are readily determinable based on certain publicly available indices.

Accounts receivable, joint interest owners, consist of uncollateralized joint interest owner obligations due within 30 days of the invoice date. Accounts receivable, oil, NGLs and gas sales, consist of uncollateralized accrued revenues due under normal trade terms, generally requiring payment within 30 to 60 days of production. No interest is charged on past-due balances. Payments made on all accounts receivable are applied to the earliest unpaid items. We review accounts receivable periodically and reduce the carrying amount by a valuation allowance that reflects our best estimate of the amount that may not be collectible. No such allowance was considered necessary at December 31, 2017 or 2016.

Oil, NGLs and Gas Sales Payable. Oil, NGLs and gas sales payable represents amounts collected from purchasers for oil, NGLs and gas sales which are either revenues due to other revenue interest owners or severance taxes due to the respective state or local tax authorities. Generally, we are required to remit amounts due under these liabilities within 60 days of the end of the month in which the related production occurred.

Production Costs. Production costs, including compressor rental and repair, pumpers' and supervisors' salaries, saltwater disposal, insurance, repairs and maintenance, expensed workovers and other operating expenses are expensed as incurred and included in lease operating expenses on our consolidated statements of operations.

Exploration expenses. Exploration expenses include lease expirations, delay rentals, geological and geophysical costs and dry hole costs. For the year ended December 31, 2015 exploration expense includes $2.2 million related to the early termination of daywork drilling contracts.

Dependence on Major Customers. For the year ended December 31, 2017, sales to American Midstream, LP (“AMID”), a successor to JP Energy Development, LP (“JP Energy”), and DCP Midstream, LP (“DCP”) accounted for approximately 52% and 47%, respectively, of our total sales. As of December 31, 2017, we had dedicated the majority of our oil production from Project Pangea through September 2022 to AMID. In addition, as of December 31, 2017, we had contracted to sell the majority of our NGLs and natural gas production from Project Pangea to DCP through August 2023. For the year ended December 31, 2016, sales to DCP and JP Energy accounted for approximately 46% and 54%, respectively of our total sales. For the year ended December 31, 2015, sales to DCP and JP Energy accounted for approximately 36% and 63%, respectively of our total sales. We believe that there are potential alternative purchasers and that it may be necessary to establish relationships with new purchasers. However, there can be no assurance that we can establish such relationships and that those relationships will result in increased purchasers. Although we are exposed to a concentration of credit risk, we believe that all of our purchasers are credit worthy.

Segment Reporting

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

Recent Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board (the “FASB”) issued an accounting standards update for “Revenue from Contracts with Customers,” which supersedes the revenue recognition requirements in “Topic 605, Revenue Recognition.” This accounting standard update provides new guidance concerning recognition and measurement of revenue and requires additional disclosures about the nature, timing and uncertainty of revenue and cash flows arising from contracts with customers. This new guidance permits adoption through the use of either a full retrospective approach or a modified retrospective approach for annual reporting periods beginning on or after December 15, 2016, with early adoption not permitted. In August 2015, FASB delayed the effective date one year, making the new standard effective for interim periods and annual periods beginning after December 15, 2017. We have completed our detailed review of our individual purchaser contracts and we have evaluated the impact of this accounting standards update on our consolidated financial statements. We adopted this standard using the modified retrospective method of adoption on January 1, 2018. Adoption of this standard did not have a significant impact on our consolidated statements of operations or cash flows. We implemented processes to ensure new contracts are reviewed for the appropriate accounting treatment and generate the disclosures required under the new standard. Additional disclosures will be required to describe the nature, amount, timing and uncertainty of revenue and cash flows from contracts with customers including disaggregation of revenue and remaining performance obligations, beginning with our Form 10-Q for the three months ended March 31, 2018.

In February 2016, FASB issued an accounting standards update for “Leases,” which amends existing guidance to require lessees to recognize assets and liabilities on the balance sheet for the rights and obligations created by long-term leases and to disclose additional quantitative and qualitative information about leasing arrangements. This new guidance is effective for interim and annual periods beginning after December 15, 2018, and we will adopt it using a modified retrospective approach. Currently, the Company is evaluating the standard’s applicability to our various contractual arrangements. We believe that the adoption this standard will result in recognition of assets and liabilities on the balance sheet for current operating leases. The Company is still evaluating the impact of this new guidance on its consolidated financial statements.

In March 2016, FASB issued an accounting standards update for "Compensation — Stock Compensation," which amends existing guidance related to the accounting for forfeitures, employer tax withholding on share-based compensation and financial statement presentation of excess tax benefits or deficiencies. This standard is effective for interim and annual reporting periods beginning after December 15, 2016, with early adoption permitted. We applied this standard using a modified retrospective approach. We have elected to (i) recognize forfeitures of share-based compensation as they occur, (ii) permit tax withholdings in excess of the minimum statutory requirements and (iii) recognize previously un-recognized excess tax benefits related to share-based compensation in the current year. As a result, we have recognized an increase in accumulated earnings in the current year of $1.7 million related to the change in accounting principal as of January 1, 2016. Adoption of this guidance did not impact our consolidated statements of operations or cash flows.

In January 2017, FASB issued an accounting standards update for "Clarifying the Definition of a Business," which provides guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. This standard requires entities to use a screen test to determine when an integrated set of assets and activities is not a business or if the integrated set of assets and activities needs to be further evaluated against the framework. This standard is effective for interim and annual reporting periods beginning after December 15, 2016. The Company is evaluating the impact of this new guidance on its consolidated financial statements.

In August 2017, FASB issued an accounting standards update for "Derivatives and Hedging," which amends existing guidance related to the recognition and presentation requirements of hedge accounting, including eliminating the requirement to separately measure and report hedge ineffectiveness, and presenting all items that affect earnings in the same income statement line item as the hedged item. This standard is effective for interim and annual reporting periods beginning after December 15, 2018, with early adoption permitted. We have elected to early adopt this standard in the first quarter of 2018. Adoption of this standard did not impact our consolidated statements of operations or cash flows. Although we have not historically designated our derivative contracts as cash-flow hedges, we may in the future designate commodity derivative contracts as cash-flow hedges.

2. Equity Exchange Transactions

Debt exchange

On November 2, 2016, we entered into an exchange agreement with Wilks Brothers, LLC and SDW Investments, LLC (collectively, "Wilks"), the largest holder of our 7% Senior Notes due 2021 (the "Senior Notes"), to exchange $130,552,000 principal amount of our Senior Notes for 39,165,600 newly issued shares of common stock, par value $0.01 per share (the "Initial Exchange"). On January 26, 2017, our stockholders approved the Exchange Transactions (defined below) and an increase in our authorized common stock from 90 million shares to 180 million shares. We closed the Initial Exchange on January 27, 2017, and paid $1.1 million of accrued interest on the Senior Notes held by Wilks. In connection with the Initial Exchange, a second supplemental indenture became effective, which removed certain covenants and events of default from the indenture governing our Senior Notes and eliminated certain restrictive covenants discussed in Note 3.

On March 22, 2017, we exchanged an additional $14,528,000 principal amount of outstanding Senior Notes for 4,009,728 shares of our common stock (the "Follow-On Exchange").

The Initial Exchange and the Follow-On Exchange (together, the "Exchange Transactions") reduced the principal amount of outstanding Senior Notes by $145.1 million and reduced interest payments by $44.3 million over the remaining term of the Senior Notes. The Exchange Transactions were accounted for as a debt extinguishment. A gain of $5.1 million was recognized on the Exchange Transactions for the difference between the fair market value of the shares issued, a Level 1 fair value measurement, and the net carrying value of the Senior Notes exchanged. We incurred equity issuance costs of $2.8 million related to the Exchange Transactions, which were recorded as a reduction to additional paid-in capital.

The Exchange Transactions triggered a cumulative change in ownership of our common stock by more than 50% under Section 382 of the Internal Revenue Code as of March 22, 2017. This established an annual limitation on the usage of our pre-change net operating losses (“NOLs”) in the future. Accordingly, we reduced our NOL deferred tax assets by $139.1 million.

Acquisition

On November 1, 2017, we entered into a definitive agreement to acquire producing properties directly adjacent to our acreage in the Permian Basin (the “Bolt-On Acquisition”). The Bolt-On Acquisition closed on November 20, 2017, and we issued 7,573,403 newly issued shares of common stock, par value $0.01 per share, with an effective date of September 1, 2017. The purchase price is subject to customary post-closing adjustments, and is expected to be finalized in the first quarter of 2018. Any adjustments to the purchase price are expected to be settled in shares of common stock. The Bolt-On Acquisition was accounted for using the acquisition method under ASC Topic 805, “Business Combinations,” which requires the acquired assets and liabilities to be recorded at fair values as of the acquisition date.

Approach Resources Inc. and Subsidiaries

Notes to Consolidated Financial Statements — (Continued)

The results of operations attributable to the Bolt-On Acquisition are included in our consolidated statements of operations beginning on November 20, 2017. We recognized revenue of $0.5 million from these assets from November 20, 2017 to December 31, 2017. In connection with the Bolt-On Acquisition, we incurred $0.1 million of acquisition-related costs which were expensed as incurred and are included in general and administrative expenses on our consolidated statements of operations.

We are in the process of identifying and determining the fair values of the assets acquired and liabilities assumed, pursuant to the Bolt-On Acquisition, and as a result, the estimates for fair value are subject to change. We anticipate certain changes, including, but not limited to, adjustments to working capital that are expected to be finalized prior to the measurement period's expiration. The following table summarizes the preliminary estimated fair value of the assets acquired and liabilities assumed as a result of the Bolt-On Acquisition (in thousands):

Accounts receivable	$558
Proved leasehold costs	13,865
Lease and well equipment	3,466
Total assets acquired	17,889
Accounts payable	(106)
Oil, NGLs and gas sales payable	(255)
Accrued liabilities	(25)
Asset retirement obligations	(71)
Total liabilities assumed	(457)
Estimated fair value of net assets acquired	$17,432

We estimated the fair value of oil and gas properties and equipment and asset retirement obligations as of November 20, 2017, using a discounted cash flow model, which is a non-recurring Level 3 fair value measurement. Significant inputs to the valuation of natural gas and oil properties include estimates of: (i) future sales prices for oil and gas based on NYMEX strip prices, (ii) pricing adjustments for differentials, (iii) production costs, (iv) future oil and gas reserves to be recovered and the timing thereof, and (v) discount rates.

3. Long-Term Debt

The following table provides a summary of our long-term debt at December 31, 2017, and December 31, 2016 (in thousands).

	December 31, 2017	December 31, 2016
Senior secured credit facility:		
Outstanding borrowings	$ 291,000	$ 273,000

Debt issuance costs	(1,725)	(1,304)
Senior secured credit facility, net	289,275	271,696
Senior notes:		
Principal	85,240	230,320
Debt issuance costs	(1,055)	(3,667)
Senior notes, net	84,185	226,653
Total long-term debt	$ 373,460	$ 498,349

Senior Secured Credit Facility

At December 31, 2017, the borrowing base and aggregate lender commitments under our amended and restated senior secured credit facility (the “Credit Facility”) were $325 million, with maximum commitments from the lenders of $1 billion. The Credit Facility has a maturity date of May 7, 2020. The borrowing base is redetermined semi-annually based on our oil, NGLs and gas reserves. We, or the lenders, can each request one additional borrowing base redetermination each calendar year.

Approach Resources Inc. and Subsidiaries

Notes to Consolidated Financial Statements — (Continued)

Borrowings under the Credit Facility bear interest based on the agent bank's prime rate plus an applicable margin ranging from 2% to 3%, or the sum of the LIBOR rate plus an applicable margin ranging from 3% to 4%. In addition, we pay an annual commitment fee of 0.50% of unused borrowings available under the Credit Facility. Margins vary based on the borrowings outstanding compared to the borrowing base of the lenders.

We had $291 million of outstanding borrowings under the Credit Facility at December 31, 2017, compared to $273 million of outstanding borrowings under the Credit Facility at December 31, 2016. The weighted average interest rate applicable to borrowings under the Credit Facility in 2017 was 4.5%. We also had outstanding unused letters of credit under our Credit Facility totaling $0.3 million at December 31, 2017, compared to $0.6 million at December 31, 2016, which reduce amounts available for borrowing under the Credit Facility.

Obligations under the Credit Facility are secured by mortgages on substantially all of the oil and gas properties of the Company and its subsidiaries. The Company is required to grant liens in favor of the lenders covering the oil and gas properties of the Company and its subsidiaries representing at least 95% of the total value of all oil and gas properties of the Company and its subsidiaries.

On December 21, 2017, we entered into a fourth amendment to the Credit Facility. The fourth amendment, among other things, (a) extended the maturity date of the Credit Facility from May 7, 2019, to May 7, 2020, (b) increased the applicable margin rates on borrowings by 50 basis points, and (c) required the Company to hedge 50% of the Company's estimated 2018 oil and gas production from proved developed producing reserves. In connection with the fourth amendment to the Credit Facility we incurred $1 million of debt issuance costs.

On May 3, 2016, we entered into a third amendment to the Credit Facility. The third amendment, among other things, (a) decreased the borrowing base to $325 million from $450 million, (b) increased the applicable margin rates on borrowings by 100 basis points, (c) permits the Company to issue up to $150 million of second lien indebtedness, subject to various conditions and limitations, (d) permits the Company to repurchase outstanding debt with proceeds of certain asset sales, equity issuances or second lien indebtedness, and (e) requires cash and cash equivalents in excess of $35 million held by the Company to be applied to reduce outstanding borrowings under the Credit Facility. In connection with the third amendment to the Credit Facility, $0.6 million of debt issuance costs were written off as a result of the reduction in the borrowing base, and we incurred $0.2 million of debt issuance costs.

Covenants

The Credit Facility contains three principal financial covenants:

- a consolidated interest coverage ratio covenant that requires us to maintain a ratio of (i) consolidated EBITDAX for the period of four fiscal quarters then ending to (ii) Cash Interest Expense for such period as of the last day of any fiscal quarter of not less than 1.5 to 1.0 through December 31, 2017, a ratio of not less than 1.75 to 1.0 through December 31, 2018, a ratio of not less than 2.25 to 1.0 through December 31, 2019, and 2.5 to 1.0 thereafter. EBITDAX is defined as consolidated net (loss) income plus (i) interest expense, net, (ii) income tax provision (benefit), (iii) depreciation, depletion, amortization, (iv) exploration expenses and (v) other noncash loss or expense (including share-based compensation and the change in fair value of any commodity derivatives), less noncash income. Cash Interest Expense is calculated as interest expense, net less amortization of debt issuance costs. At December 31, 2017, our consolidated interest coverage ratio was 2.7 to 1.0;
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a consolidated modified current ratio covenant that requires us to maintain a ratio of not less than 1.0 to 1.0 as of the last day of any fiscal quarter. The consolidated modified current ratio is defined as the ratio of (i) current assets plus funds available under our revolving credit facility, less the current derivative asset, to (ii) current liabilities less the current derivative liability. At December 31, 2017, our consolidated modified current ratio was 2.1 to 1.0; and

- a consolidated total leverage ratio covenant that imposes a maximum permitted ratio of (i) Total Debt to (ii) EBITDAX for the period of four fiscal quarters then ending of not more than 5.0 to 1.0, as of the last day of any fiscal quarter from March 31, 2019, through June 30, 2019, thereafter not more than 4.75 to

1.0 as of the last day of any fiscal quarter through December 31, 2019, and (iii) not more than 4.0 to 1.0 as of the last day of any fiscal quarter thereafter. Total Debt is defined as the face or principal amount of debt. Our leverage ratio is currently above the level that will be required as of March 31, 2019.

The Credit Facility also contains covenants restricting cash distributions and other restricted payments, transactions with affiliates, incurrence of other debt, consolidations and mergers, the level of operating leases, asset sales, investment in other entities and liens on properties.

In addition, the obligations of the Company may be accelerated upon the occurrence of an Event of Default (as defined in the Credit Facility). Events of Default include customary events for a financing agreement of this type, including, without limitation, payment defaults, the inaccuracy of representations and warranties, defaults in the performance of affirmative or negative covenants, defaults on other indebtedness of the Company or its subsidiaries, bankruptcy or related defaults, defaults related to judgments and the occurrence of a Change of Control (as defined in the Credit Facility), which includes instances where a third party becomes the beneficial owner of more than 50% of the Company's outstanding equity interests entitled to vote.

Senior Notes

In June 2013, we completed our public offering of $250 million principal amount of 7% Senior Notes due 2021 (the "Senior Notes"). Annual interest on the Senior Notes is payable semi-annually on June 15 and December 15. On December 15, 2017, we made a semi-annual interest payment of $3 million. We received net proceeds from the issuance of the Senior Notes of approximately $243 million, after deducting fees and expenses. We used a portion of the net proceeds from the offering to repay all outstanding borrowings under the Credit Facility, fund our capital expenditures for the development of our Wolfcamp shale oil resource play and for general working capital needs.

During the year ended December 31, 2017, we completed the Exchange Transactions which reduced the outstanding principal balance of our Senior Notes by $145.1 million and reduced future interest payments by $44.3 million over the remaining term of the Senior Notes.

During the year ended December 31, 2015, we repurchased Senior Notes in the open market with an aggregate face value of $19.7 million for a purchase price of $8.8 million, including accrued interest. This resulted in a gain on extinguishment of debt of $10.6 million.

Wilks, a related party, purchased a portion of our outstanding Senior Notes in the open market subsequent to the Exchange Transactions. The Company believes that Wilks held approximately $43 million of our outstanding Senior Notes as of December 31, 2017. The Senior Notes held by Wilks are included in Senior Notes, net on our consolidated balance sheets. Our interest expense includes interest attributable to any Senior Notes held by Wilks on our consolidated statements of operations. As of December 31, 2017, we recorded a current liability $0.1 million of accrued interest attributable to the Senior Notes held by Wilks.

We issued the Senior Notes under a senior indenture dated June 11, 2013, among the Company, our subsidiary guarantors and Wilmington Trust, National Association, as successor trustee. The senior indenture, as supplemented by a supplemental indenture dated June 11, 2013, is referred to as the "Indenture."

On December 20, 2016, we entered into the second supplemental indenture (the “Second Supplemental Indenture”), which became effective on January 27, 2017, in connection with the closing of the Initial Exchange. The Second Supplemental Indenture (i) eliminated certain definitions and references to definitions contained in the Indenture, (ii) eliminated and revised, as applicable, certain events of default contained in the Indenture, (iii) eliminated certain conditions to consolidation, merger, conveyance, transfer or lease contained in the Indenture, (iv) eliminated certain covenants contained in the Indenture, including substantially all of the restrictive covenants set forth therein, and (v) supplemented and amended the Senior Notes and the securities guarantees, as and to the same extent as the Indenture has been amended and supplemented in accordance with the preceding clauses (i), (ii), (iii) and (iv).

We may redeem some or all of the Senior Notes at specified redemption prices, plus accrued and unpaid interest to the redemption date. The Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by each of our subsidiaries, subject to certain customary release provisions. A subsidiary guarantor may be released from its obligations under the guarantee:

- in connection with any sale or other disposition of all or substantially all of the assets of that guarantor (including by way of merger or consolidation) to a person that is not (either before or after giving effect to such transaction) the Company or a subsidiary guarantor, if the sale or other disposition otherwise complies with the Indenture;
- in connection with any sale or other disposition of the capital stock of that guarantor to a person that is not (either before or after giving effect to such transaction) the Company or a subsidiary guarantor, if that guarantor no longer qualifies as a subsidiary of the Company as a result of such disposition and the sale or other disposition otherwise complies with the Indenture;
- if the Company designates any restricted subsidiary that is a guarantor to be an unrestricted subsidiary in accordance with the Indenture;
- upon defeasance or covenant defeasance of the notes or satisfaction and discharge of the indenture, in each case, in accordance with the Indenture;
- upon the liquidation or dissolution of that guarantor, provided that no default or event of default occurs under the indenture as a result thereof or shall have occurred and is continuing; or
- in the case of any restricted subsidiary that, after the issue date of the notes is required under the indenture to guarantee the notes because it becomes a guarantor of indebtedness issued or an obligor under the revolving credit facility with respect to the Company and/or its subsidiaries, upon the release or discharge in full from its (i) guarantee of such indebtedness or (ii) obligation under such revolving credit facility, in each case, which resulted in such restricted subsidiary’s obligation to guarantee the notes.

As a result of the Second Supplemental Indenture, the Indenture contains limited events of default.

Subsidiary Guarantors

The Senior Notes are guaranteed on a senior unsecured basis by each of our consolidated subsidiaries. Approach Resources Inc. is a holding company with no independent assets or operations. The subsidiary guarantees are full and unconditional and joint and several, and any subsidiaries of the Company other than the subsidiary guarantors are minor. There are no significant restrictions on the Company’s ability, or the ability of any subsidiary guarantor, to obtain funds from its subsidiaries through dividends, loans, advances or otherwise.

At December 31, 2017, we were in compliance with all of our covenants, and there were no existing defaults or events of default, under our debt instruments.

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4. Termination Costs

In September 2015, we reduced our workforce to decrease costs and better align our workforce with the needs of the business and oil and gas prices. In connection with the reduction, we incurred $1.4 million in expenses, which was recorded in termination costs on our consolidated statements of operations. As of December 31, 2017, there was no remaining liability related to termination costs on our consolidated balance sheets. We also recorded a benefit of $0.3 million in share-based compensation expense related to the forfeiture of unvested shares of restricted stock in connection with our workforce reduction, which was recorded in general and administrative expense on our consolidated statements of operations.

5. Share-Based Compensation

In June 2007, our board of directors and stockholders approved the 2007 Stock Incentive Plan (the “2007 Plan”). Under the 2007 Plan, we may grant restricted stock, stock options, stock appreciation rights, restricted stock units, performance awards, unrestricted stock awards and other incentive awards. The maximum number of shares of common stock available for the grant of awards under the 2007 Plan is 6,125,000. Awards of any stock options are to be priced at not less than the fair market value at the date of the grant. We use (i) the closing stock price on the date of grant for the fair value of restricted stock awards, including performance-based awards, (ii) the Monte Carlo simulation method for the fair value of market-based awards, (iii) the fair market value of our common stock on the valuation date for cash-settled performance awards and (iv) the Black-Scholes option price model to measure the fair value of stock options. The vesting period of any stock award is to be determined by the board or an authorized committee at the time of the grant.

Share-based compensation expense amounted to $4.7 million, $6.3 million and $8 million for the years ended December 31, 2017, 2016 and 2015, respectively. Such amounts represent the estimated fair value of stock awards for which the requisite service period elapsed during those periods. Share-based compensation expense for the years ended December 31, 2017, 2016 and 2015, included $449,000, $214,000 and $735,000, respectively, related to grants to non-employee directors.

Stock Options

There were no stock option grants during the years ended December 31, 2017, 2016 and 2015. During the year ended December 31, 2017, 38,525 options expired, and no options were outstanding as of December 31, 2017. There were no options exercised during the years ended December 31, 2017, 2016 and 2015.

Nonvested Shares

Share grants totaling 2,343,522 shares, 1,318,229 shares and 1,278,329 shares with an approximate aggregate fair market value of $5.6 million, $2.5 million and $6.2 million, based on the closing price of our common stock on the date of grant, were granted to employees and non-employee directors during the years ended December 31, 2017, 2016 and 2015, respectively. Included in the share grants for 2017, 2016 and 2015, are 1,492,652 shares, 550,272 shares and 724,249 shares, respectively, awarded to our executive officers. The aggregate fair market value of these shares on the grant date was $3.6 million, $0.3 million and $4.5 million, respectively, to be expensed over a service period of approximately three years, subject to certain performance restrictions. The share grants for executive officers noted above does not include the cash-settled performance awards, which are discussed in more detail below.

Approach Resources Inc. and Subsidiaries

Notes to Consolidated Financial Statements — (Continued)

A summary of the status of nonvested shares for the years ended December 31, 2017, 2016 and 2015, is presented below:

	Shares	Weighted Average Grant-Date Fair Value
Nonvested at January 1, 2015	1,122,410	$ 16.52
Granted	1,278,329	4.87
Vested	(419,222)	15.26
Canceled	(246,261)	14.30
Nonvested at December 31, 2015	1,735,256	$ 8.60
Granted	1,318,229	1.90
Vested	(992,461)	7.03
Canceled	(107,960)	17.33
Nonvested at December 31, 2016	1,953,064	$ 4.39
Granted	2,343,522	2.39
Vested	(902,197)	6.73
Canceled	(89,728)	5.17
Nonvested at December 31, 2017	3,304,661	$ 2.21

As of December 31, 2017, unrecognized compensation expense related to the nonvested shares amounted to $4 million, which will be recognized over a remaining service period of two years.

Cash-settled performance awards

In 2016, in addition to the share grants discussed above, we awarded 1,100,543 cash-settled performance awards, subject to certain performance conditions, to our executive officers. The aggregate fair market value of the cash-settled shares on the grant date was approximately $1 million, to be expensed over a remaining service period of approximately two years, subject to performance conditions.

The cash-settled performance awards represent a non-equity unit with a conversion value equal to the fair market value of a share of the Company’s common stock at the vesting date. These awards are classified as liability awards due to the cash settlement feature. Compensation costs associated with the cash-settled performance awards are re-measured, based on the fair market value of our common stock of the vested portion of the award, at each interim reporting period and an adjustment is recorded in general and administrative expenses on our consolidated statements of operations. For the years ended December 31, 2017, and December 31, 2016, we recognized $0.8 million and $1.3 million in expense related to the cash-settled performance awards, respectively. As of December 31, 2017, we recorded a current liability of $1.6 million and a non-current liability of $0.5 million on our consolidated balance sheet related to these awards.

Subsequent Restricted Share Award

Subsequent to December 31, 2017, 774,590 cash settled performance awards, subject to certain performance conditions, and 387,295 restricted shares, subject to three-year total shareholder return (“TSR”) conditions, assuming maximum TSR, were granted to our executive officers. The aggregate fair market value of the cash settled performance awards and TSR restricted shares on the date of grant was approximately $2.4 million and $0.8 million, respectively, to be expensed over a remaining service period of approximately three years.

Employee Benefit Plan

The Company has a defined contribution employee benefit plan covering substantially all of its employees. We make a matching contribution equal to 100% of each pre-tax dollar contributed by the participant on the first 3% of eligible compensation and 50% on the next 2% of eligible compensation. The Company made contributions to the plan of approximately $333,000, $338,000 and $404,000 during the years ended December 31, 2017, 2016 and 2015, respectively.

Approach Resources Inc. and Subsidiaries

Notes to Consolidated Financial Statements — (Continued)

6. Income Taxes

Our provision for income taxes comprised the following (in thousands):

	Years Ended December 31,		
	2017	2016	2015
Current:			
Federal	$(66)	$—	$(265)
State	—	—	—
Total current provision for income taxes	$(66)	$—	$(265)
Deferred:			
Federal	$75,341	$(24,957)	$(91,716)
State	1,146	539	(1,424)
Total deferred provision for income taxes	$76,487	$(24,418)	$(93,140)

Total income tax expense differed from the amounts computed by applying the U.S. Federal statutory tax rates to pre-tax income (in thousands):

	Years Ended December 31,		
	2017	2016	2015
Statutory tax at 35%	$(12,578)	$(26,831)	$(93,628)
State taxes, net of federal impact	528	578	(1,463)
Share-based compensation tax shortfall	1,279	1,826	1,939
Permanent differences	11	11	26
Other differences	30	(2)	(1,035)
Change in federal tax rate	(51,939)	—	—
Write-off of deferred tax assets	139,090	—	756
Total	$76,421	$(24,418)	$(93,405)

In 2017, the Exchange Transactions triggered a cumulative change in ownership of our common stock by more than 50% under Section 382 of the Internal Revenue Code as of March 22, 2017. This established an annual limitation on the future use of our pre-change net operating losses (“NOLs”). Accordingly, we reduced our NOL deferred tax assets by $139.1 million.

On December 22, 2017, the Tax Cuts and Jobs Act was enacted which, among other things, lowered the U.S. Federal income tax rate applicable to corporations from 35% to 21% and repealed the corporate alternative minimum tax. We recorded a net tax benefit of $51.9 million to reflect the impact of the Tax Cuts and Jobs Act as of December 31, 2017, as it is required to reflect the change in the period in which the law is enacted.

In 2017, 2016 and 2015, the Company recorded a tax shortfall related to share-based compensation of $1.3 million, $1.8 million and $1.9 million, respectively. This shortfall is for grants in which the realized tax deduction was less than the expense booked for these grants due to a decline in share price from the time of grant.

In 2016, we early adopted accounting standards update for "Compensation — Stock Compensation." As a result, we recognized an increase in accumulated earnings and our NOLs in 2016 of $1.7 million related to the change in accounting principal as of January 1, 2016.

Deferred tax assets and liabilities are the result of temporary differences between the financial statement carrying values and tax basis of assets and liabilities. Our net deferred tax assets and liabilities are recorded as a long-term liability of $82.1 million and $5.6 million at December 31, 2017 and 2016, respectively.

Approach Resources Inc. and Subsidiaries

Notes to Consolidated Financial Statements — (Continued)

Significant components of net deferred tax assets and liabilities are (in thousands):

	Years Ended December 31, 2017	2016
Deferred tax assets:		
Net operating loss carryforwards	$39,991	$155,018
Derivative liabilities	471	1,732
Other	533	892
Total deferred tax assets	40,995	157,642
Deferred tax liabilities:		
Difference in depreciation, depletion and capitalization methods — oil and gas properties	(122,335)	(162,501)
Derivative assets	(302)	—
Total deferred tax liabilities	(122,637)	(162,501)
Valuation allowance	(460)	(756)
Net deferred tax liability	$(82,102)	$(5,615)

The Exchange Transactions triggered a cumulative change in ownership of our common stock by more than 50% under Section 382 of the Internal Revenue Code as of March 22, 2017. This established an annual limitation on the future use of our pre-change NOLs. Accordingly, we reduced our NOL deferred tax assets by $139.1 million in the year ended December 31, 2017. At December 31, 2017, we had federal NOLs of $190.4 million, after the reduction under Section 382 limitation, that expire between 2030 and 2037. As of December 31, 2017, we have a valuation allowance of $0.5 million on our deferred tax assets, after accounting for the change in the corporate federal income tax rate under the Tax Cuts and Jobs Act.

7. Derivative Instruments and Fair Value Measurements

At December 31, 2017, we had the following commodity derivatives positions outstanding:

Commodity and Period	Contract Type	Volume Transacted	Contract Price
Crude Oil			
January 2018 — December 2018	Swap	300 Bbls/day	$50.00/Bbl
January 2018 — March 2018	Collar	1,000 Bbls/day	$50.00/Bbl - $55.05/Bbl

January 2018 — June 2018	Collar	500 Bbls/day	$55.00/Bbl - $60.00/Bbl
Natural Gas			
January 2018 — December 2018	Swap	200,000 MMBtu/month	$3.085/MMBtu
January 2018 — December 2018	Swap	250,000 MMBtu/month	$3.084/MMBtu
NGLs (C3 - Propane)			
January 2018 — March 2018	Swap	450 Bbls/day	$30.24/Bbl
NGLs (IC4 - Isobutane)			
January 2018 — March 2018	Swap	50 Bbls/day	$36.12/Bbl
NGLs (NC4 - Butane)			
January 2018 — March 2018	Swap	150 Bbls/day	$35.70/Bbl

After December 31, 2017, we entered into the following commodity derivative positions:

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Commodity and Period	Contract Type	Volume Transacted	Contract Price
Crude Oil			
January 2018 — September 2018	Swap	700 Bbls/day	$60.50/Bbl
April 2018 — September 2018	Swap	800 Bbls/day	$60.50/Bbl
NGLs (C2 - Ethane)			
February 2018 — December 2018	Swap	1,000 Bbls/day	$11.424/Bbl
NGLs (C3 - Propane)			
February 2018 — December 2018	Swap	600 Bbls/day	$32.991/Bbl
NGLs (IC4 - Isobutane)			
February 2018 — December 2018	Swap	50 Bbls/day	$38.262/Bbl
NGLs (NC4 - Butane)			
February 2018 — December 2018	Swap	200 Bbls/day	$38.22/Bbl
NGLs (C5 - Pentane)			
January 2018 — December 2018	Swap	200 Bbls/day	$56.364/Bbl

The following summarizes the fair value of our open commodity derivatives as of December 31, 2017 and 2016 (in thousands):

	Balance Sheet Location	Fair Value	
		December 31, 2017	December 31, 2016
Derivatives not designated as hedging instruments			
Commodity derivatives	Derivative assets	$1,398	$ —
Commodity derivatives	Derivative liabilities	(2,181)	(4,880)

The following summarizes the cash settlements and change in the fair value of our commodity derivatives (in thousands):

	Year Ended December 31,		
	2017	2016	2015
Derivatives not designated as hedging instruments			
Commodity derivatives	$ (4,359)	$ 6,132	$ 52,489

Net cash (payment) receipt on derivative settlements			
Non-cash fair value gain (loss) on derivatives	4,097	(11,616)	(33,214)
Commodity derivative (loss) gain	$ (262)	$ (5,484)	$ 19,275

Derivative assets and liabilities, at fair value, are included on our consolidated balance sheets as current or non-current assets or liabilities based on the anticipated timing of cash settlements under the related contracts. Changes in the fair value of our commodity derivative contracts are recorded in earnings as they occur and included in income (expense) on our consolidated statements of operations. We estimate the fair value of swap contracts based on the present value of the difference in exchange-quoted forward price curves and contractual settlement prices multiplied by notional quantities. We internally valued the option contracts using industry-standard option pricing models and observable market inputs. We use our internal valuations to determine the fair values of the contracts that are reflected on our consolidated balance sheets.

We are exposed to credit losses in the event of nonperformance by the counterparties on our commodity derivatives positions and have considered the exposure in our internal valuations. However, we do not anticipate nonperformance by the counterparties over the term of the commodity derivatives positions.

To estimate the fair value of our commodity derivatives positions, we use market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally

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unobservable. We primarily apply the market approach for recurring fair value measurements and attempt to use the best available information. We determine the fair value based upon the hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and lowest priority to unobservable inputs (Level 3 measurement). The three levels of fair value hierarchy are as follows:

- Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. At December 31, 2017, we had no Level 1 measurements.
- Level 2 — Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Our derivatives, which consist primarily of commodity swaps and collars, are valued using commodity market data which is derived by combining raw inputs and quantitative models and processes to generate forward curves. Where observable inputs are available, directly or indirectly, for substantially the full term of the asset or liability, the instrument is categorized in Level 2. At December 31, 2017, all of our commodity derivatives were valued using Level 2 measurements.
- Level 3 — Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. The fair value of oil and gas properties acquired in the Bolt-on Acquisition represents a Level 3 measurement. The fair value of oil and gas properties used in estimating our recognized impairment loss in 2015 represents a nonrecurring Level 3 measurement. At December 31, 2017, we had no recurring Level 3 measurements.

Nonrecurring Fair Value Measurements

We recorded no impairment of our proved properties for the years ended December 31, 2017, and 2016. Due to the impact of the decline in forward commodity prices during the year ended December 31, 2015, there were indications that the carrying values of certain of our oil and gas properties may be impaired and undiscounted cash flows attributable to these assets indicated their carrying amounts were not expected to be recovered. For the year ended December 31, 2015, we recognized an impairment loss of $214.7 million related primarily to our vertical Canyon wells, due to the impact of the decline in forward commodity prices. At September 30, 2015, we had $22 million in value recorded for these properties, which was the estimated fair value. We estimated the fair value of the proved oil and gas properties and equipment using a discounted cash flow model, which is a Level 3 fair value measurement. Significant inputs used to determine the fair value include estimates of (i) future sales prices for oil and gas based on NYMEX strip prices, (ii) pricing adjustments for differentials, (iii) production costs, (iv) capital expenditures, (v) future oil and gas reserves to be recovered and the timing thereof, and (vi) discount rates.

Financial Instruments Not Recorded at Fair Value

The following table sets forth the fair values of financial instruments that are not recorded at fair value on our financial statements (in thousands).

	December 31, 2017	
	Carrying Amount	Fair Value
Senior Notes, net	$84,185	$74,798

The fair value of the Senior Notes is based on quoted market prices, but the Senior Notes are not actively traded in the public market. Accordingly, the fair value of the Senior Notes would be classified as Level 2 in the fair value hierarchy.

8. Commitments and Contingencies

At December 31, 2017, we had outstanding employment agreements with all four of our executive officers that contained automatic renewal provisions providing that such agreements may be automatically renewed for successive terms of one year unless the employment is terminated at the end of the term by written notice given to the employee not less than 60 days prior to the end of such term. Our maximum commitment under the employment agreements, which would apply if the employees covered by these agreements were each terminated without cause, resigned for good reason, or received a notice of non-renewal was approximately $6.3 million at December 31, 2017. This estimate assumes the maximum potential bonus for 2017 is earned by each executive officer during 2017.

In 2016, we recorded a contractual settlement of $1.4 million, which is recorded in other income on our consolidated statements of operations.

We lease our office space in Fort Worth, Texas, under a non-cancelable agreement that expires on September 30, 2021. We also have non-cancelable operating lease commitments related to office equipment that expire by 2022. The following is a schedule by years of future minimum rental payments required under our operating lease arrangements as of December 31, 2017 (in thousands):

2018	$852
2019	861
2020	875
2021	673
2022	4
Total	$3,265

Rent expense under our lease arrangements amounted to $748,000, $1,025,000 and $1,002,000 for the years ended December 31, 2017, 2016 and 2015, respectively.

Litigation

We are involved in various legal and regulatory proceedings arising in the normal course of business. While we cannot predict the outcome of these proceedings with certainty, we do not believe that an adverse result in any pending legal or regulatory proceeding, individually or in the aggregate, would be material to our consolidated financial condition or cash flows.

In 2016, we received $1.1 million from a service provider in a legal settlement, which reduced our current liabilities on our consolidated balance sheets and is recorded as a reduction in additions to oil and gas properties on our consolidated statements of cash flows.

Environmental Issues

We are engaged in oil and gas exploration and production and may become subject to certain liabilities or damages as they relate to environmental clean up of well sites or other environmental restoration or ground water contamination, in connection with drilling or operating oil and gas wells. In connection with our acquisition of existing or previously drilled well bores, we may not be aware of what environmental safeguards were taken at the time such wells were drilled or during such time the wells were operated. Should it be determined that a liability exists with respect to any environmental clean up, restoration or contamination, we would be responsible for curing such a violation or paying damages. No claim has been made, nor are we aware of any liability that exists, as it relates to any environmental clean up, restoration, contamination or the violation of any rules or regulations relating thereto.

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9. Oil and Gas Producing Activities

Set forth below is certain information regarding the costs incurred for oil and gas property acquisition, development and exploration activities (in thousands):

	For the Years Ended December 31,		
	2017	2016	2015
Property acquisition costs:			
Unproved properties	$231	$17	$653
Proved properties(1)	17,331	—	—
Exploration costs	3,657	3,923	4,439
Development costs(2)	43,202	15,884	146,237
Total costs incurred	$64,421	$19,824	$151,329

(1) For the year ended December 31, 2017, acquisition costs of proved properties included the fair value of assets acquired in the Bolt-On Acquisition. See Note 2 for additional disclosures related to the Bolt-On Acquisition.

(2) For the years ended December 31, 2017, 2016 and 2015, development costs included $39,000, $36,000 and $151,000, respectively, in non-cash asset retirement obligations.

Set forth below is certain information regarding the results of operations for oil and gas producing activities (in thousands):

	For the Years Ended December 31,		
	2017	2016	2015
Revenues	$105,349	$90,302	$131,336
Production costs	(26,546)	(27,467)	(40,057)
Exploration expense	(3,657)	(3,923)	(4,439)
Depletion	(70,521)	(79,044)	(109,319)
Impairment of oil and gas properties	—	—	(220,197)
Income tax benefit (expense)	(1,641)	7,144	86,120
Results of operations	$2,984	$(12,988)	$(156,556)

10. Disclosures About Oil and Gas Producing Activities (unaudited)

Proved Reserves

All of our estimated oil and natural gas reserves are attributable to properties within the United States, primarily in the Permian Basin in West Texas. The estimates of proved reserves and related valuations for the years ended

December 31, 2017, 2016 and 2015, were prepared by DeGolyer and MacNaughton, independent petroleum engineers. Each year's estimate of proved reserves and related valuations were also prepared in accordance with then-current rules and guidelines established by the Securities and Exchange Commission and the Financial Accounting Standards Board.

The following table summarizes the prices used in the reserve estimates for 2017, 2016 and 2015. Commodity prices used for the reserve estimates, adjusted for basis differentials, grade and quality, are as follows:

	2017	2016	2015
Oil (per Bbl)	$51.34	$42.69	$50.16
Natural gas liquids (per Bbl)	$18.67	$14.12	$15.13
Gas (per Mcf)	$2.99	$2.47	$2.64

Oil, NGLs and natural gas reserve estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and

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Notes to Consolidated Financial Statements — (Continued)

geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward or downward revision of previous estimates. Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of currently producing oil and natural gas properties. Accordingly, these estimates are expected to change as additional information becomes available in the future.

The following table provides a summary of the changes of the total proved reserves for the years ended December 31, 2017, 2016 and 2015, as well as proved developed and proved undeveloped reserves at the beginning and end of each respective year.

	Oil	NGLs	Natural Gas	Total
Total Proved Reserves	(MBbls)	(MBbls)	(MMcf)	(MBoe)
Balance — January 1, 2015	55,338	40,907	300,020	146,248
Extensions and discoveries	11,054	10,630	79,268	34,895
Production(1)	(1,882)	(1,694)	(13,262)	(5,787)
Revisions to previous estimates	(10,014)	(357)	9,962	(8,710)
Balance — December 31, 2015	54,496	49,486	375,988	166,646
Extensions and discoveries	6,529	4,564	33,347	16,651
Production(1)	(1,275)	(1,529)	(11,734)	(4,759)
Revisions to previous estimates	(9,719)	(4,887)	(45,324)	(22,161)
Balance — December 31, 2016	50,031	47,634	352,277	156,377
Extensions and discoveries	10,546	9,975	76,710	33,307
Acquisition of minerals in place	710	394	2,808	1,572
Production(1)	(1,107)	(1,486)	(11,148)	(4,452)
Revisions to previous estimates	(10,120)	1,431	20,581	(5,259)
Balance — December 31, 2017	50,060	57,948	441,228	181,545

(1) Production included 1,530 MMcf, 1,330 MMcf and 1,319 MMcf related to field fuel in 2015, 2016 and 2017, respectively.

	Oil	NGLs	Natural Gas	Total
Total Proved Reserves	(MBbls)	(MBbls)	(MMcf)	(MBoe)
Proved Developed Reserves:				

January 1, 2015	17,978	19,082	138,961	60,220
December 31, 2015	15,667	20,414	154,652	61,856
December 31, 2016	13,466	20,375	150,208	58,875
December 31, 2017	13,853	23,180	176,201	66,399
Proved Undeveloped Reserves:				
January 1, 2015	37,360	21,825	161,059	86,028
December 31, 2015	38,829	29,072	221,335	104,790
December 31, 2016	36,565	27,259	202,069	97,502
December 31, 2017	36,207	34,768	265,028	115,146

The following is a discussion of the material changes in our proved reserve quantities for the years ended December 31, 2017, 2016 and 2015:

Year Ended December 31, 2017

Extensions and discoveries for 2017 were 33.3 MMBoe, primarily attributable to our development project in the Wolfcamp shale oil resource play in the Permian Basin. During 2017, we acquired 1.6 MMBoe of proved reserves through the Bolt-On Acquisition, and we reclassified 17.7 MMBoe of proved undeveloped reserves to unproved reserves. The reserves reclassified are attributable to horizontal well locations in Project Pangea that are no longer expected to be developed within five years from their initial booking, as required by SEC rules. Revisions included an increase of 9.4 MMBoe resulting from updated well performance and technical parameters and an increase of 3.1 MMBoe due to higher commodity prices We produced 4.5 MMBoe during 2017. This production included 1,319 MMcf of gas that was produced and used as field fuel (primarily for compressors and artificial lift) before the gas was delivered to a sales point.

Year Ended December 31, 2016

Extensions and discoveries for 2016 were 16.7 MMBoe, primarily attributable to our development project in the Wolfcamp shale oil resource play in the Permian Basin. During 2016, we reclassified 22.4 MMBoe of proved undeveloped reserves to unproved reserves. The reserves reclassified are attributable to horizontal well locations in Project Pangea that are no longer expected to be developed within five years from their initial booking, as required by SEC rules. Revisions included an increase of 2.1 MMBoe resulting from cost reductions, updated well performance and technical parameters, offset by a decrease of 1.9 MMBoe due to lower commodity prices. We produced 4.8 MMBoe during 2016. This production included 1,330 MMcf of gas that was produced and used as field fuel (primarily for compressors and artificial lift) before the gas was delivered to a sales point.

Year Ended December 31, 2015

Extensions and discoveries for 2015 were 34.9 MMBoe, primarily attributable to our development project in the Wolfcamp shale oil resource play in the Permian Basin. During 2015, we reclassified 11.9 MMBoe of proved reserves to unproved reserves. The reserves reclassified are attributable to horizontal and vertical well locations in Project Pangea that are no longer expected to be developed within five years from their initial booking, as required by SEC rules. Revisions included an increase of 13 MMBoe resulting from cost reductions, updated well performance and technical parameters, offset by a decrease of 9.8 MMBoe due to lower commodity prices. We produced 5.8 MMBoe during 2015. This production included 1,530 MMcf of gas that was produced and used as field fuel (primarily for compressors and artificial lift) before the gas was delivered to a sales point.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves

The standardized measure of discounted future net cash flows is computed by applying the 12-month unweighted average of the first-day-of-the-month pricing for oil and natural gas (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved oil and natural gas reserves less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, discounted using a rate of 10 percent per year to reflect the estimated timing of the future cash flows. Future income taxes are calculated by comparing undiscounted future cash flows to the tax basis of oil and natural gas properties plus available carryforwards and credits and applying the current tax rates to the difference.

Discounted future cash flow estimates like those shown below are not intended to represent estimates of the fair value of oil and natural gas properties. Estimates of fair value would also consider probable and possible reserves, anticipated future oil and natural gas prices, interest rates, changes in development and production costs and risks associated with future production. Because of these and other considerations, any estimate of fair value is necessarily subjective and imprecise.

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The following table provides the standardized measure of discounted future net cash flows at December 31, 2017, 2016 and 2015 (in thousands):

	Years Ended December 31,		
	2017	2016	2015
Future cash flows	$4,451,665	$3,319,551	$4,097,568
Future production costs	(1,279,777)	(1,054,211)	(1,237,888)
Future development costs	(982,284)	(829,926)	(934,814)
Future income tax expense	(323,308)	(132,834)	(307,374)
Future net cash flows	1,866,296	1,302,580	1,617,492
10% annual discount for estimated timing of cash flows	(1,405,265)	(1,004,825)	(1,157,097)
Standardized measure of discounted future net cash flows	$461,031	$297,755	$460,395

Future cash flows as shown above were reported without consideration for the effects of commodity derivative transactions outstanding at each period end.

Changes in Standardized Measure of Discounted Future Net Cash Flows

The changes in the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves are as follows (in thousands):

	Years Ended December 31,		
	2017	2016	2015
Balance, beginning of period	$297,755	$460,395	$1,055,815
Net change in sales and transfer prices and in production (lifting) costs related to future production	229,139	(191,841)	(1,405,864)
Changes in estimated future development costs	(72,439)	17,405	231,900
Sales and transfers of oil and gas produced during the period	(78,803)	(62,835)	(91,278)
Net change due to acquisition of minerals in place	17,331	—	—
Net change due to extensions, discoveries and	49,377	13,988	156,783

improved recovery			
Net change due to revisions in quantity estimates	(3,817)	(25,236)	(59,305)
Previously estimated development costs incurred during the period	43,202	15,884	146,237
Accretion of discount	30,789	46,040	105,582
Other	(1,677)	(9,500)	6,915
Net change in income taxes	(49,826)	33,455	313,610
Standardized Measure of discounted future net cash flows	$461,031	$297,755	$460,395

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11. Supplementary Data

Selected Quarterly Financial Data (unaudited), (dollars in thousands, except per-share amounts):

	2017 Quarters Ended			
	December 31	September 30	June 30	March 31
Net revenues	$28,417	$ 25,608	$24,969	$26,355
Net operating expenses	(29,365)	(29,543)	(34,689)	(31,460)
Interest expense, net	(5,370)	(5,304)	(4,916)	(5,463)
Gain on debt extinguishment	—	—	—	5,053
Commodity derivative (loss) gain	(1,377)	(3,560)	1,231	3,444
Other income (expense)	—	29	—	3
Loss before income tax benefit	(7,695)	(12,770)	(13,405)	(2,068)
Income tax (benefit) provision	(53,512)	(4,258)	(4,509)	138,700
Net income (loss)	$45,817	$ (8,512)	$(8,896)	$(140,768)
Basic net earnings (loss) applicable to common stockholders per common share	$0.51	$ (0.10)	$(0.10)	$(2.00)
Diluted net earnings (loss) applicable to common stockholders per common share	$0.51	$ (0.10)	$(0.10)	$(2.00)

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	2016 Quarters Ended			
	December 31	September 30	June 30	March 31
Net revenues	$26,505	$ 23,749	$22,433	$17,615
Net operating expenses	(33,564)	(32,201)	(34,534)	(34,869)
Interest expense, net	(7,086)	(7,067)	(6,808)	(6,298)
Write-off of debt issuance costs	—	—	(563)	—
Commodity derivative (loss) gain	(2,901)	1,541	(6,667)	2,543
Other income (expense)	—	(10)	1,417	104
Loss before income tax benefit	(17,046)	(13,988)	(24,722)	(20,905)
Income tax benefit	(3,571)	(4,915)	(8,687)	(7,245)
Net loss	$(13,475)	$ (9,073)	$(16,035)	$(13,660)
Basic net loss applicable to common stockholders per common share	$(0.32)	$ (0.22)	$(0.39)	$(0.33)
Diluted net loss applicable to common stockholders per common share	$(0.32)	$ (0.22)	$(0.39)	$(0.33)

	2015 Quarters Ended			
	December 31	September 30	June 30	March 31
Net revenues	$25,492	$ 33,941	$38,605	$33,298
Net operating expenses	(38,671)	(272,462)	(46,970)	(45,686)
Interest expense, net	(6,436)	(6,465)	(6,243)	(5,922)
Gain on debt extinguishment	9,080	1,483	—	—
Commodity derivative gain (loss)	4,267	13,051	(4,623)	6,580
Other income (expense)	225	(91)	12	26
Loss before income tax benefit	(6,043)	(230,543)	(19,219)	(11,704)
Income tax benefit	(284)	(81,756)	(7,369)	(3,996)
Net loss	$(5,759)	$ (148,787)	$(11,850)	$(7,708)
Basic net loss applicable to common stockholders per common share	$(0.14)	$ (3.67)	$(0.29)	$(0.19)
Diluted net loss applicable to common stockholders per common share	$(0.14)	$ (3.67)	$(0.29)	$(0.19)