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, 2015

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	**51-0424817**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification Number)*
One Ridgmar Centre 6500 West Freeway, Suite 800 Fort Worth, Texas	**76116**
(Address of principal executive offices)	*(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, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐ Accelerated filer ☑ Non-accelerated filer ☐ Smaller reporting company ☐

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates (excluding voting shares held by officers and directors) as of June 30, 2015 was $247 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 February 29, 2016 was 40,842,788.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's proxy statement for its 2016 annual meeting of stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2015, 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" are 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" at the end of Item 15 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," "estimate," "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, NGL and natural gas prices;
- overall United States and global economic and financial market conditions;
- domestic and foreign demand and supply for oil, NGLs, natural gas and the products derived from such hydrocarbons;
- the willingness and ability of the Organization of Petroleum Exporting Countries ("OPEC") to set and maintain 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;
- 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, NGL 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, NGL 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 126,000 net acres as of December 31, 2015. We believe our concentrated acreage position 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. 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, 2015, our estimated proved reserves were 166.6 million barrels of oil equivalent ("MMBoe"). Substantially all of our proved reserves are located in Crockett and Schleicher Counties, Texas. Important characteristics of our proved reserves at December 31, 2015, include:

- 33% oil, 30% NGLs and 37% natural gas;
- 37% proved developed;
- 100% operated;
- Reserve life of approximately 30 years based on 2015 production of 5.5 MMBoe;
- Standardized measure of discounted future net cash flows of ("standardized measure") of $460.4 million; and
- PV-10 (non-GAAP) of $504 million.

PV-10 is our estimate of the present value of future net revenues from proved oil, NGL 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, 2015, we owned and operated 803 producing oil and gas wells in the Permian Basin. During 2015, we produced 5.5 MMBoe, or 15.2 MBoe/d. Production for 2015 was 34% oil, 31% NGLs and 35% 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 growth of our reserves and production, as well as achievable rates of return, depends on commodity prices. During 2014-2015, we experienced dramatic price decreases in the commodities we produce. During that period, NYMEX-WTI oil dropped from a high of $107.26 per Bbl to a low of $34.73 per Bbl, NYMEX-Henry Hub natural gas dropped from a high of $6.15 per MMBtu to a low of $1.76 per MMBtu, and our realized prices for NGLs dropped from a high of $37.31 per Bbl to a low of $8.33 per Bbl.

Through the first two months of 2016, commodity prices had not recovered sufficiently to allow us to resume our long-term business strategy of growth. Accordingly, until commodity prices show meaningful signs of recovery, our business strategy is focused on the following:

- ***Operate our business at or near cash-flow breakeven.*** In August 2015, in response to declining commodity prices, we made the decision to temporarily suspend our drilling and completion operations. As a result, in the fourth quarter of 2015, we generated positive cash flow and reduced our outstanding borrowings under our revolving credit facility. We also repurchased a portion of our 7% Senior Notes due 2021 (the "Senior Notes") in the open market at a discount to par. In 2016, we have reduced our expected capital expenditure budget to a range of $20 million to $80 million, compared to $151.2 million of actual capital expenditures in 2015. We believe this reduction should allow us to maintain capital expenditures closer to our expected cash flows. We have the operational flexibility to adjust our capital spending upward in response to a commodity price recovery. Operating our business closer to cash flow breakeven will help us preserve liquidity so that we will be able to accelerate execution of our long-term strategy when commodity prices recover. Because we operate 100% of our reserve base, we also have the flexibility to further adjust our capital budget downward in response to further commodity price decreases.
- ***Explore alternatives to strengthen our balance sheet and preserve financial flexibility.*** We intend to explore and have discussed with select parties various alternatives to strengthen our balance sheet and preserve financial flexibility. These alternatives 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, and private or public equity raises and rights offerings. Many of these alternatives may require the consent of current lenders, stockholders or bond holders. There is no assurance that we will be able to execute any of these alternatives on acceptable terms or at all.

Once commodity prices show signs that we believe indicate a meaningful and sustained price recovery, we intend to resume growing our reserves and production in a cost-efficient manner and at attractive rates of return by pursuing the following strategies:

- ***Develop our Wolfcamp shale oil resource play.*** We believe our current acreage position provides us the long-term ability to continue to increase reserves and production at competitive costs and at attractive rates of return in a normalized commodity price environment. During 2015, we drilled 20, and completed 28, horizontal Wolfcamp wells. With our 2016 drilling plan, we plan to continue to develop our core properties in Project Pangea, although at a materially reduced pace from 2015 due to significant, continued declines in commodity prices. 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.
- ***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 field infrastructure including water recycling systems and transportation, centralized production facilities, gas lift lines and salt water disposal wells, we have significantly reduced drilling and completion costs, per-unit lease operating expense and our fresh water use over the last two years. We

also may drill multiple wells from a single pad, which will reduce well costs and surface impact. In addition, we operate 100% of our reserve base, which allows us to better manage timing and scope of capital expenditures and control costs.

- ***Mitigate commodity price volatility.*** We enter into commodity derivative contracts to partially mitigate the risk of commodity price volatility. For 2015, we hedged approximately 86% and 38% of our oil and gas production, respectively, which resulted in a realized gain on commodity derivatives of $52.5 million. For 2016, we currently have 547,500 Bbls of oil hedged at an average price of $51.33 per Bbl and 6,400,000 MMBtu of gas hedged at an average price of $2.60 per MMBtu.

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 780 wells in the area since 2004. Our proved reserves are 63% liquids, and our production for 2015 was 65% liquids. Our acreage position of 138,000 gross, 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.

- ***High degree of operational control.*** We operate 100% of our estimated proved reserves, and we have approximately 100% 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.

- ***Prudent financial management.*** As of December 31, 2015, we had 55% equity capitalization and liquidity of approximately $177 million. We are committed to a disciplined capital program and exploring alternatives to strengthen our balance sheet. 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 creating stockholder value.

2015 Activity

Our 2015 activity focused on horizontal drilling in the Wolfcamp shale oil resource play in the Midland Basin. We drilled 20, and completed 28, horizontal wells in 2015. In addition, we made a strategic investment in building a large-scale water recycling system, which reduces drilling and completion costs, per-unit lease operating expense and our fresh water use. We plan to continue to develop the Wolfcamp shale in Project Pangea in 2016, although at a materially reduced pace from 2015, subject to commodity prices. Our activities in 2015 included:

- ***Production Growth.*** Production for 2015 totaled 5.5 MMBoe (15.2 MBoe/d), compared to 5 MMBoe (13.8 MBoe/d) in 2014, a 10% increase. Production for 2015 was 34% oil, 31% NGLs and 35% natural gas. We operated an average of one horizontal rig in 2015, drilled a total of 20, and completed 28, horizontal wells. At December 31, 2015, five wells were waiting on completion.

- ***Reserve Growth.*** In 2015, our estimated proved reserves increased 14%, or 20.4 MMBoe, to 166.6 MMBoe from 146.2 MMBoe. Our proved reserves at year-end 2015 were 33% oil, 30% NGLs and 37% natural gas. Reserve growth in 2015 was driven by results in our Wolfcamp shale oil resource play.

- ***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, 2015, we had drilled a total of 16 wells targeting the Wolfcamp A bench, 105 wells targeting the Wolfcamp B bench and 43 wells targeting the Wolfcamp C bench. We have successful wells targeting each of the Wolfcamp benches, and we continued development in 2015.
- ***Installation of Field Infrastructure and Water Recycling Systems.*** Our large, mostly contiguous acreage position and our success in the Wolfcamp shale oil play led us to invest over $110 million in building field infrastructure since 2012. We continued the infrastructure build out in 2015, and now have an extensive network of centralized production facilities, water transportation 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.

Plans for 2016

In March 2016, in response to continued, depressed oil, NGL and gas prices and uncertain market conditions, we announced that we were reducing our capital expenditure budget to a range of $20 million to $80 million in 2016, compared to $151.2 million of actual capital expenditures in 2015. At current commodity prices, we plan to drill six horizontal wells and complete five horizontal wells. We resumed drilling in 2016, and currently have one rig running. We expect to release this rig in the first quarter of 2016. We have the operational flexibility to increase the capital budget in case of a commodity price recovery in 2016 or to further adjust our capital budget downward in response to further commodity price decreases.

Our 2016 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 a sustained, low 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, NGL and 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, seasonality, 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, 2015, sales to JP Energy Development, LP ("JP Energy") and DCP Midstream, LP ("DCP") accounted for approximately 63% and 36%, respectively, of our total sales. As of December 31, 2015, we had dedicated all of our oil production from northern Project Pangea and Pangea West through 2022 to JP Energy. In addition, as of December 31, 2015, we had dedicated all of our NGLs and natural gas production from Project Pangea to DCP through July 2023.

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 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 2015, we realized $52.5 million in gains from our derivatives contracts, and the estimated fair value of our derivatives contracts at December 31, 2015, was $6.7 million. For 2016, we currently have derivatives contracts covering 547,500 Bbls of oil at an average price of $51.33 per Bbl, and 6,400,000 MMBtu of gas at an average price of $2.60 per MMBtu.

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 non-producing and proved undeveloped reserves associated with this acreage. All of our proved non-producing and 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 that are subject to supervision by state regulators. 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.

Hydraulic fracturing requires the use of a significant amount of water. Upon flowback of the water, we dispose of it in a way that we believe minimizes the impact to nearby surface water by disposing into approved disposal facilities or injection wells. 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 also reuse and recycle flowback and produced water.

For information regarding existing and proposed governmental regulations regarding hydraulic fracturing and related environmental matters, please read “Business — Regulation — Environmental Laws and Regulation” and “Business — Regulation — Hydraulic Fracturing.” 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.”

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) 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 material compliance with federal, state and local rules, regulations and procedures, 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 NGL 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, NGL and gas production is regulated under a wide range of federal and state statutes, rules, orders and regulations. 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. The failure to comply with these rules and regulations can result in substantial penalties. 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 begins;
- require the installation of expensive pollution controls or emissions monitoring equipment;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and gas drilling, completion, production, transportation and processing activities;
- suspend, limit or prohibit construction, drilling and other activities in certain lands lying within 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 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.

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, for damages to natural resources and for the costs of 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. Crude oil and fractions of crude oil are excluded from regulation under CERCLA. Nevertheless, many chemicals commonly used at oil and gas production facilities fall outside of the CERCLA 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 potentially 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 auspices of the EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced water and most of the 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 classified as non-hazardous could be classified 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. 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 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. In particular, on April 18, 2012, the EPA issued new regulations under the New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAP"). The new regulations are designed to reduce volatile organic compound ("VOC") emissions from hydraulically fractured natural gas wells, storage tanks and other equipment. Under the 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. We do not expect that the NSPS or NESHAP 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 permit requirements or use specific equipment or technologies to control emissions. For example, on August 18, 2015, the EPA proposed a suite of additional permitting rules for the oil and gas industry. The proposed rules would require methane and VOC emissions reductions from hydraulically fractured oil wells and would impose more stringent requirements on operators to inspect and repair equipment to prevent leaks. While we cannot predict whether EPA will finalize these rules or, if finalized, what regulatory proposals will be retained, the additional regulatory requirements could increase our compliance costs. 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 greenhouse gases ("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 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 Clean Air Act. The EPA has adopted two sets of rules regarding possible future regulation of GHG emissions under the Clean Air Act, 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 April 2010 and became effective in January 2011, but it does not require immediate reductions in GHG emissions. On August 3, 2015, the EPA issued a final rule to limit GHG emissions from new power plants. The agency simultaneously released a final rule to limit carbon emissions from existing power plants. While these regulations are currently the subject of litigation, including a stay issued by the U.S. Supreme Court, if the regulation ultimately is upheld 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. 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 December 2010, the EPA enacted final rules on mandatory reporting of GHGs. In 2011, the EPA published amendments to the rule containing technical and clarifying changes to certain GHG reporting requirements and a six-month extension for reporting GHG emissions from petroleum and natural gas industry sources. Under the amended rule, 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 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 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 or reduce GHG emissions could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, acquire emissions allowances or comply with new regulatory requirements. In addition, the EPA has stated that the data collected from GHG emissions reporting programs may be the basis for future regulatory action to establish substantive GHG emissions factors. 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") 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. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

In October 2011, the EPA announced its intent to develop national standards for wastewater discharges produced by natural gas extraction from shale and coalbed methane formations. The EPA is expected to issue proposed regulations establishing wastewater discharge standards for coalbed methane wastewater and shale gas wastewater in 2016. For shale gas wastewater, the EPA will consider imposing pre-treatment standards for discharges to a wastewater treatment facility. Produced and other flowback water from our current operations in the Permian Basin is typically re-injected into underground formations that do not contain potable water. To the extent that re-injection is not available for our operations and discharge to wastewater treatment facilities is required, new standards from the EPA could increase the cost of disposing wastewater in connection with our 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 are 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 October 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 new 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 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. Specifically, the Fracturing Responsibility and Awareness of Chemicals Act ("FRAC Act") has been introduced in each Congress since 2008 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.

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 February 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 draft results in 2015. 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 June 2011, the RRC enacted a rule in December 2011, 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.

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, 2015. 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 2016. 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.

Threatened and Endangered Species, Migratory Birds and Natural Resources

Various state and federal statutes prohibit certain actions that adversely affect endangered or threatened species and their habitat, migratory birds, wetlands and natural resources. These statutes include the Endangered Species Act, the Migratory Bird Treaty Act, the Clean Water Act and CERCLA. The United States Fish and Wildlife Service may designate critical habitat and suitable habitat areas that it believes are necessary for 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 prevent oil and gas exploration activities or seek damages for harm to species, habitat or natural resources resulting from drilling or construction or 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 Occupational Safety and Health Act (“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 or produced 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.

Employees

As of February 18, 2016, we had 102 full-time employees, 62 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 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.

Risks Related to the Oil and Gas Industry and Our Business

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:

- continued, depressed oil, NGL and gas prices or further declines in these commodity 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; and
- mechanical difficulties.

Oil, NGL and gas prices are volatile. If oil, NGL or gas prices remain depressed, or decline further, it 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;
- the willingness and ability of OPEC to set and maintain 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, NGL 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 fall dramatically. For example, prices for NYMEX-WTI have declined from a high of $107.26 per Bbl in June 2014 to as low as $26.55 per Bbl in January 2016. NYMEX-Henry Hub natural gas prices declined from a high of $6.15 per MMBtu in February 2014 to as low as $1.76 per MMBtu in December 2015. Prices may stay suppressed for some time from the levels experienced during the last few years. Any actual or anticipated lack of recovery, or further decline, in oil and natural gas prices 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 stay depressed for an extended period of time.

The ways that continued low oil and gas prices 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
- We expect our borrowing base under our revolving credit facility to 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 remain at their current, depressed levels or decline further, 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, NGL or gas prices further decline or fail to recover from their current depressed 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 recent 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. We expect that our borrowing base will be redetermined in the first quarter or early second quarter of 2016. We expect that the redetermination will result in a material reduction in our borrowing base in the range of 20% to 30%, but there is no assurance that the decrease will not be higher or lower than our expectation. Additionally, we expect an increase in the applicable margin rates used to determine the interest on our outstanding borrowings under our revolving credit facility. If commodity prices fail to recover, or decline further, it is likely that we will be subject to a further reduction in our borrowing base at our scheduled redetermination in the fall of 2016. In addition, our revolving credit facility contains various financial covenants. Sustained low prices, or further decreases in oil, NGL and natural gas prices, may result in our breach of those covenants.

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 2015 reserve report, the estimated future capital required to develop our current proved oil and gas reserves is $935 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. 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 do not recover or if they decline further, 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 $230.3 million principal amount of Senior Notes and $273 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; or
- refinancing or restructuring our 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 would 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, 2015, we had $273 million in borrowings outstanding under our revolving credit facility, and our borrowing base was $450 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. We expect that our borrowing base will be redetermined in the first quarter or early second quarter of 2016. We expect that the redetermination will result in a material reduction in our borrowing base in the range of 20% to 30%, but there is no assurance that the decrease will not be higher or lower than our expectation. Upon a further redetermination, our borrowing base could be reduced again, 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 the significant reduction in commodity prices continues or accelerates, it is likely that our borrowing base will be reduced further in the next semi-annual borrowing base 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 and the indenture governing our Senior Notes contain 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 and the indentures governing our Senior Notes (the "Indenture") contain, 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 and Indenture also contain financial covenants. Our ability to comply with some of the covenants and restrictions contained in our revolving credit facility and the Indenture may be affected by events beyond our control. If market or other economic conditions do not improve, or if commodity prices remain at their current depressed 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, the Indenture 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.

A payment default or an acceleration under our revolving credit facility could result in an event of default and acceleration of indebtedness under the Senior Notes.

If the indebtedness under the Senior Notes were to be accelerated, there can be no assurance that we would have, or be able to obtain, sufficient funds to repay such indebtedness in full. In addition, our obligations under our revolving credit facility are collateralized by perfected first-priority liens and security interests on substantially all of our Permian Basin assets in West Texas and a pledge of equity interests of certain subsidiaries, and if we are unable to repay our indebtedness under our revolving credit facility, the lenders could seek to foreclose on our assets.

Price declines during 2015 resulted in a material write down of the carrying values of our properties, and further price declines could result in additional write downs in the future, which would negatively impact our net income and results of operations. 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 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.

During the third quarter of 2015, we recorded an impairment loss of $214.7 million related primarily to our vertical Canyon wells as a result of a sharp decline in forward commodity prices at the measurement date. Prices have remained volatile and depressed since the third quarter of 2015. This and other factors could cause a future, additional write down of capitalized costs and a non-cash charge against future earnings, which could have a material adverse effect on our results of operations for the periods in which such charges are taken.

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 continued, depressed 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, 2015, we reclassified 11.9 MMBoe of proved reserves to unproved reserves 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.

The estimated volumes, standardized measure and present value of future net revenues ("PV-10") from our proved reserves as of December 31, 2015, calculated using SEC pricing will be higher than these measures calculated using current market prices.

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. 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.

Our estimated proved reserves as of December 31, 2015, and related PV-10 and standardized measure, were calculated under SEC rules using 12-month trailing average benchmark prices of $50.16 per Bbl of oil, $15.13 per Bbl of NGLs and $2.64 per Mcf of gas. At the end of January 2016, the prompt month NYMEX-WTI futures price for oil was $33.62 per Bbl and the prompt month NYMEX-Henry Hub futures price for gas was $2.29 per MMBtu. Our realized price for NGLs was $8.33 per Bbl for the month ended December 31, 2015. Using lower commodity prices than those required by the SEC would reduce the PV-10 and standardized measure of our proved reserves and result in a reduction of proved reserves due to economic limit.

A decrease of 10% or 25% in the oil, NGL and gas prices used in our reserve report as of December 31, 2015, holding production and development costs constant, would result in:

- a decrease in our PV-10 as of December 31, 2015 of 27% and 49%, respectively,
- a decrease in our total proved reserves of 36% and 64%, respectively, and
- a decrease in our proved undeveloped reserves of 56% and 98%, respectively.

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.

Consequently, standardized measure and PV-10 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 included herein 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 debt reduction, working capital or acquisitions. 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 2015, the price of our common stock fluctuated from a high of $9.57 per share to a low of $1.23 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.

If our stock price trades below $1.00 for 30 consecutive business days, our common stock may be subject to delisting from the NASDAQ Global Select Market.

If at any time the bid price of our common stock closes at below $1.00 per share for more than 30 consecutive trading days, we may be subject to delisting from the NASDAQ Global Select Market. If we receive a delisting notice, we would have 180 calendar days to regain compliance, during which time we would anticipate reviewing our options to regain compliance with the minimum bid requirements, including conducting a reverse stock split. To the extent that we are unable to resolve the listing deficiency, there is a risk that our common stock may be delisted from NASDAQ, which would adversely impact liquidity of our common stock and potentially result in even lower bid prices for our common stock. As of February 29, 2016, our stock had traded at a 52 week low of $0.60 per share, and a 52 week high of $9.57 per share. Our closing share price on February 29, 2016, was $0.75.

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

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, results of operations and cash flows.

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 (the “CFTC”) and other regulators.

Although we have hedged a portion of our estimated 2016 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 on approximately 547,500 Bbls of oil and on approximately 6,400,000 MMBtu of natural gas hedged with swaps in 2016 at average prices of $51.33 per Bbl and $2.60 per MMBtu, respectively. 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 2016 or our production after 2016. We have not entered into any significant derivative transactions for our anticipated 2017 oil or gas production. To the extent that the prices for oil and gas remain at current levels or decline further, we will not be able to hedge future production at the same level as our current hedges, and our results of operations and financial condition would be negatively impacted.

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 non-producing and 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 to permitting delays and increases in costs. These developments, as well as new laws or regulations, 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.

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 October 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. 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, results of operations and cash flows.

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 Clean Air Act. The EPA also issued final regulations under the NSPS and NESHAP designed to reduce VOCs. 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.

If Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products. In any event, in 2013 the Obama administration announced its Climate Action Plan, which, among other things, directs federal agencies to develop a strategy for the reduction of methane emissions, including emissions from the oil and gas industry. The EPA is in the process of gathering information regarding methane emissions from the oil and gas industry and the agency may decide to pursue formal rulemaking in the future. As part of the Climate Action Plan, the Obama administration also announced that it intends to adopt additional regulations to reduce emissions of GHGs and to encourage greater use of low-carbon technologies in the coming years.

On an international level, the United States is one of almost 200 nations that agreed in December 2015 to an international climate change agreement in Paris, France that calls for countries to set their own GHG emissions targets and be transparent about the measures each country will use to achieve its GHG emissions targets.

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 late 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.

Changes in tax laws or fees may adversely affect our results of operations and cash flows.

The administration of President Obama has made budget proposals which, if enacted into law by Congress, would potentially increase and accelerate the payment of U.S. federal income taxes and fees by independent oil and gas producers. Proposals have included, but have not been limited to, repealing the enhanced oil recovery credit, repealing the credit for oil and gas produced from marginal wells, repealing the expensing of intangible drilling costs (“IDCs”), repealing the deduction for the cost of qualified tertiary expenses, repealing the exception to the passive loss limitation for working interests in oil and gas properties, repealing the percentage depletion allowance, repealing the manufacturing tax deduction for oil and gas companies, instituting a $10 per barrel fee on oil and increasing the amortization period of geological and geophysical expenses. Legislation that would have implemented many of the proposed changes has been introduced but not enacted. It is unclear whether legislation supporting any of the above described proposals, or designed to accomplish similar objectives, will be introduced or, if introduced, would be enacted into law or, if enacted, how soon resulting changes would become effective. However, the passage of any legislation designed to implement changes in the U.S. federal income tax laws or fees similar to the changes included in the budget proposals offered by the Obama administration could eliminate certain tax deductions currently available with respect to oil and gas exploration and development, and any such changes could make it more costly for us to explore for and develop our oil and gas resources, and could negatively affect our financial condition and results of operations.

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

We began drilling wells in the Wolfcamp play relatively recently. 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 2015, JP Energy and DCP collectively accounted for 99% of our total oil, NGL and gas sales, excluding realized commodity derivative settlements. As of December 31, 2015, we had dedicated all of our oil production from northern Project Pangea and Pangea West through 2022 to JP Energy. In addition, as of December 31, 2015, we had dedicated all of our NGL and natural gas production from Project Pangea to DCP through July 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 January 2011, we entered into an amended and restated employment agreement with J. Ross Craft, P.E., our Chairman, President and Chief Executive Officer; and new employment agreements with Qingming Yang, our Chief Operating Officer; and J. Curtis Henderson, our Chief Administrative Officer. On January 3, 2014, we entered into an employment agreement with Sergei Krylov as the Company's Executive Vice President and Chief Financial 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, NGL and gas markets or delay our production or sales.

Market conditions or the unavailability of satisfactory oil, NGL and gas processing and transportation services and infrastructure may hinder our access to oil, NGL 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, NGL 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 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, NGL 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, 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.

If commodity prices recover, 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 higher 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.

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, NGL 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.

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, 2015, 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. Unless we continue to develop and produce on the properties subject to these leases, most of these leases will expire between 2016 and 2018. If these leases expire, we will lose our right to develop the related properties, unless we renew such leases. 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 over the next three years. Acreage set to expire over the next three years accounts for 28% of our net acreage, and less than 1% of our proved undeveloped reserves.

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

As of December 31, 2015, 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.

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

Our business could be materially and adversely affected by severe weather. Repercussions of severe weather conditions may include:

- curtailment of services, including oil, NGL 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, NGL and gas prices, variations in levels of production and the completion of development projects.

If commodity prices do not improve or worsen or if we are unable to increase our liquidity, we could experience downgrades from ratings agencies.

In February 2016, we were downgraded by two ratings agencies. If commodity prices do not improve or worsen or if we are unable to increase our liquidity, we could experience further downgrades in our corporate or debt ratings. Credit rating agencies continually review their ratings for the companies and for the securities they follow. A negative change in our ratings or the perception that such a change could occur may adversely affect the market price of our securities.

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:

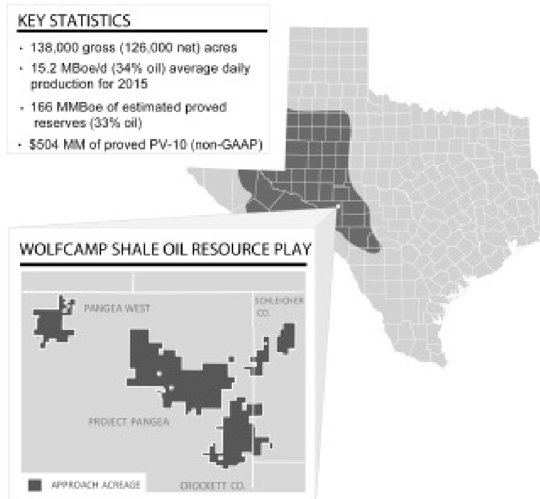
- it was presented to the Designated Party solely in that person's capacity as a director of our Company and with respect to which, at the time of such presentment, no other Designated Party has independently received notice of, or otherwise identified the business opportunity; or
- the opportunity was 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*

As of the date of this filing, we have no unresolved comments from the staff of the SEC.

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 138,000 gross (126,000 net) acres as of year-end 2015. At December 31, 2015, we owned interests in approximately 803 gross (791 net) wells, all of which we operate. As of December 31, 2015, we had working and net revenue interests of approximately 100% 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 2011, 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, 2015, we have drilled and completed a total of 16 wells targeting the Wolfcamp A bench, 105 wells targeting the Wolfcamp B bench and 43 wells targeting the Wolfcamp C bench; and, as a result, our proved reserves attributable to the horizontal Wolfcamp play have increased.

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The following table summarizes our estimated proved reserves attributable to the horizontal Wolfcamp shale oil play, compared to our estimated proved reserves attributable to vertical development for the years ended December 31, 2015, 2014 and 2013.

	Proved Reserves (MBoe)		
	2015	2014	2013
Horizontal Wolfcamp			
Proved developed	49,843	40,678	23,520
Proved undeveloped	104,790	84,138	58,073
Total	154,633	124,816	81,593
Percent of total proved reserves	93%	85%	71%
Other Vertical			
Proved developed	12,013	19,542	21,669
Proved undeveloped	—	1,890	11,399
Total	12,013	21,432	33,068
Percent of total proved reserves	7%	15%	29%
Total proved reserves	166,646	146,248	114,661

During 2015, we incurred costs of approximately $139.1 million to drill 20, and complete 28, horizontal Wolfcamp wells. At December 31, 2015, we had five horizontal Wolfcamp wells waiting on completion. We resumed drilling in 2016, and currently have one rig running in Project Pangea. We expect to release this rig in the first quarter of 2016.

East Texas Basin — North Bald Prairie

In July 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 began drilling operations in August 2007. We have drilled and completed 11 gross wells, including one well completed as a saltwater disposal well. 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, 2015, we had estimated proved reserves of 457 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, 2015. 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 $50.16 per Bbl West Texas Intermediate posted oil price, $15.13 per Bbl received for NGLs and $2.64 per MMBtu Henry Hub spot natural gas price during 2015. 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

Reserves Category	Proved Reserves Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)(1)	Total (MBoe)	Percent (%)	PV-10 (in millions)(2)
Proved Developed						
Permian Basin	15,667	20,414	154,195	61,780	37.0%	$ 391.8
East Texas Basin	—	—	457	76	0.1	0.1
Proved Undeveloped						
Permian Basin	38,829	29,072	221,336	104,790	62.9	112.1
Total Proved Reserves	54,496	49,486	375,988	166,646	100.0%	$ 504

(1) The gas reserves contain 42,617 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, 2015, were 166.6 MMBoe, made up of 33% oil, 30% NGLs and 37% natural gas. The proved developed portion of total proved reserves at year-end 2015 was 37%.

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 recorded net downward revisions totaling 8.7 MMBoe, including the reclassification of 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 also included 13 MMBoe of positive revisions resulting from cost reductions, updated well performance and technical parameters, offset by 9.8 MMBoe of negative revisions 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.

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, 2015:

	December 31, 2015 (in millions)
PV-10	$ 504
Present value of future income tax discounted at 10%	(43.6)
Standardized measure of discounted future net cash flows	$ 460.4

Proved Undeveloped Reserves

As of December 31, 2015, we had 104.8 MMBoe of proved undeveloped ("PUD") reserves, which is an increase of 18.8 MMBoe, or 22%, compared with 86 MMBoe of PUD reserves at December 31, 2014. All of our PUD reserves at December 31, 2015, were associated with our core development project, Project Pangea.

The following table summarizes the changes in our PUD reserves during 2015.

	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total (MBoe)
Balance — December 31, 2014	37,360	21,825	161,059	86,028
Extensions and discoveries	9,407	9,125	68,055	29,874
Revisions to previous estimates	(5,453)	(251)	3,959	(5,044)
Conversion to proved developed reserves	(2,485)	(1,627)	(11,737)	(6,068)
Balance — December 31, 2015	38,829	29,072	221,336	104,790

The following table sets forth our PUD reserves converted to proved developed reserves during 2015, 2014 and 2013 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)
2013	4,831	1,765	10,569	8,357	$ 108,811
2014	3,430	1,645	10,753	6,867	106,309
2015	2,485	1,627	11,737	6,068	84,071
Total	10,746	5,037	33,059	21,292	$ 299,191

Estimated future development costs relating to the development of PUD reserves are projected to be approximately $84.7 million in 2016, $175.2 million in 2017 and $254.8 million in 2018. 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 Chief Operating Officer. Our executive management, including our Chief Executive Officer 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 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, 2015, 2014 and 2013, 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 2015, 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, 2015, NGLs represented approximately 30% 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 2015 averaged approximately 72% 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, 2015, 2014 and 2013, 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 2015 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, NGL 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	**2015**	**2014**	**2013**
Oil (MBbls)	1,882	2,024	1,444
NGLs (MBbls)	1,694	1,461	951
Gas (MMcf)(1)	11,732	9,383	6,177
Total (MBoe)	5,532	5,049	3,424
Total (MBoe/d)	15.2	13.8	9.4
Average prices			
Oil (per Bbl)	$ 43.65	$87.69	$90.70
NGLs (per Bbl)	12.06	28.74	29.57
Gas (per Mcf)	2.45	4.16	3.60
Total (per Boe)	23.74	51.20	52.95
Realized gain (loss) on commodity derivatives (per Boe)	9.49	0.47	(0.31)
Total including derivative impact (per Boe)	$ 33.23	$51.67	$52.64
Production costs (per Boe)(2)	$ 5.24	$ 6.48	$ 5.59

(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 is made up of lease operating expenses and excludes production and ad valorem taxes.

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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,					
	2015		2014		2013	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	20.0	20.0	68.0	68.0	45.0	45.0
Dry(1)	1.0	1.0	2.0	2.0	5.0	5.0
Exploratory wells:						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total wells:						
Productive	20.0	20.0	68.0	68.0	45.0	45.0
Dry	1.0	1.0	2.0	2.0	5.0	5.0

(1) The Company encountered mechanical issues while drilling the wells classified as dry in 2015, 2014 and 2013.

Of the 20 productive wells drilled in 2015, five wells were waiting on completion at December 31, 2015. The Company encountered mechanical issues while drilling one well in 2015, two wells in 2014 and five wells in 2013, and these wells cost $2.4 million, $5.6 million and $12.4 million, respectively.

Although a well may be classified as productive upon completion, future changes in oil, NGL 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 one horizontal rig running in the Permian Basin targeting the Wolfcamp shale oil resource play.

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, 2015, we had dedicated all of our oil production from northern Project Pangea and Pangea West through 2022 to JP Energy and had dedicated all of our NGLs and natural gas production from Project Pangea to DCP through July 2023.

Producing Wells

The following table sets forth the number of producing wells in which we owned a working interest at December 31, 2015. 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	529	518	274	273	803	791	98.5%
East Texas Basin	10	5	—	—	10	5	50.0%
Total	539	523	274	273	813	796	97.9%

Acreage

The following table summarizes our developed and undeveloped acreage as of December 31, 2015.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Permian Basin	89,710	81,209	48,445	44,459	138,155	125,668
East Texas Basin	3,481	1,687	—	—	3,481	1,687
Total	93,191	82,896	48,445	44,459	141,636	127,355

Undeveloped Acreage Expirations

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2015, which will expire over the next three years by project area, 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.

	2016		2017		2018	
	Gross	Net	Gross	Net	Gross	Net
Permian Basin	4,253	5,130	31,115	30,480	—	35
East Texas Basin	—	—	—	—	—	—
Total	4,253	5,130	31,115	30,480	—	35

The expiring acreage set forth in the table above accounts for 28% of our net acreage, and less than 1% of our PUD reserves. Of the 30,480 net acres scheduled to expire in 2017, 16,844 net acres are leased from The Board for Lease of University Lands (“University Lands”) under a Drilling and Development Unit Agreement (“D&D agreement”). Under the D&D agreement, we are required to drill and complete two wells per calendar year until September 2017, and in September 2017, 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. 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 or cash flows.

ITEM 4. *MINE SAFETY DISCLOSURES*

Not applicable.

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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 2015, trading volume averaged 1,088,912 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
2015		
First quarter	$ 9.15	$ 5.01
Second quarter	9.57	6.35
Third quarter	6.95	1.65
Fourth quarter	3.19	1.23
2014		
First quarter	$24.00	$18.33
Second quarter	23.04	17.59
Third quarter	23.07	14.30
Fourth quarter	14.88	4.28

Holders

As of February 19, 2016, there were 167 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 and the Indenture governing our Senior Notes currently restrict 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

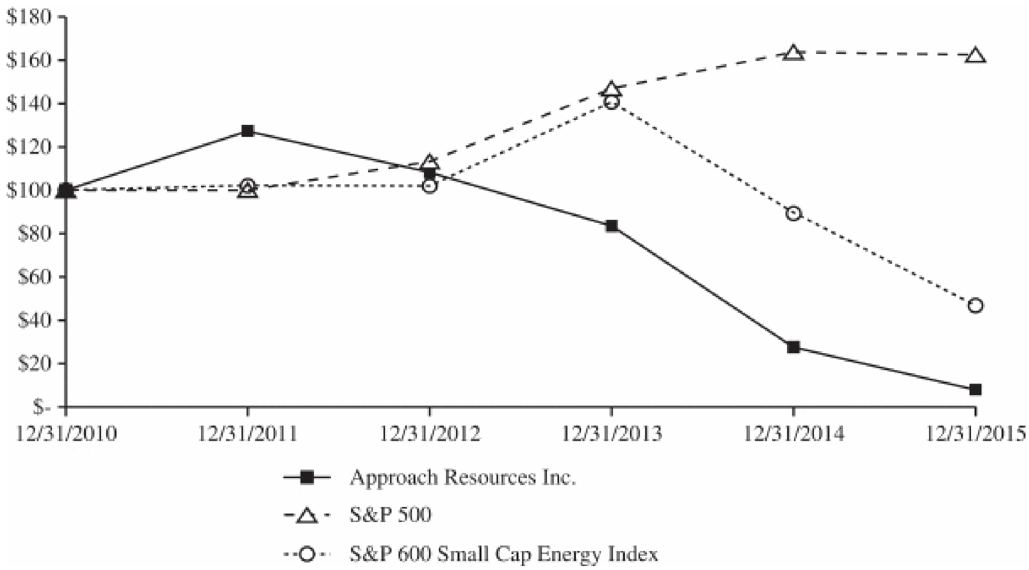
The following table sets forth information regarding securities authorized for issuance under equity compensation plans and individual compensation arrangements as of December 31, 2015.

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans (Excluding Securities Reflected in Column (a))(1) (c)
Equity compensation plans approved by stockholders	38,525	$ 12.00	1,452,663
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, 2010, through December 31, 2015, 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



	12/31/2010	12/31/2011	12/31/2012	12/31/2013	12/31/2014	12/31/2015
Approach Resources Inc.	$ 100.00	$ 127.32	$ 108.27	$ 83.55	$ 27.66	$ 7.97
S&P 500	100.00	100.00	113.40	146.97	163.71	162.52
Dow Jones U.S. Exploration & Production[1]	100.00	96.40	99.88	129.41	112.29	83.25
S&P 600 Small Cap Energy Index	100.00	102.26	101.97	140.81	89.83	46.99

1 In our 2014 Form 10-K performance graph, we included the Dow Jones U.S. Exploration & Production Total Stock Market Index (the "Dow Jones E&P Index"). For the 2015 Form 10-K, we have replaced the Dow Jones E&P Index with the S&P 600 Small Cap Energy Index (the "S&P 600"). We believe a comparison of our cumulative return with the S&P 600 is more informative because the S&P 600 reflects the performance of companies in our line of business that are closer to us in market capitalization.

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, 2015 — October 31, 2015	—	$ —	—	—
November 1, 2015 — November 30, 2015	358	2.71	—	—
December 1, 2015 — December 31, 2015	41,621	1.88	—	—
Total	41,979	$ 1.89	—	—

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ITEM 6. *SELECTED FINANCIAL DATA*

The following table sets forth selected financial information for the five years ended December 31, 2015. 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,				
	2015	2014	2013	2012	2011
	(in thousands, except per-share data)				
Operating Results Data					
Revenues					
Oil, NGL and gas sales	$ 131,336	$ 258,529	$ 181,302	$ 128,892	$ 108,387
Expenses					
Lease operating	28,972	32,701	19,152	19,002	10,687
Production and ad valorem taxes	11,085	15,934	12,840	9,255	8,447
Exploration	4,439	3,831	2,238	4,550	9,546
Impairment of oil and gas properties	220,197	—	—	—	18,476
General and administrative	28,341	32,104	26,524	24,903	17,900
Termination costs	1,436	—	—	—	—
Depletion, depreciation and amortization	109,319	106,802	76,956	60,381	32,475
Total expenses	403,789	191,372	137,710	118,091	97,531
Operating (loss) income	(272,453)	67,157	43,592	10,801	10,856
Other					
Interest expense, net	(25,066)	(21,651)	(14,084)	(4,737)	(3,402)
Gain on debt extinguishment	10,563	—	—	—	—
Equity in (losses) earnings of investee	—	(181)	156	(108)	—
Gain on sale of equity method investment	—	—	90,743	—	—
Realized gain (loss) on commodity derivatives	52,489	2,359	(1,048)	(108)	3,375
Unrealized (loss) gain on commodity derivatives	(33,214)	42,113	(4,596)	3,874	(347)
Other income	172	67	—	—	—
Gain on sale of oil and gas properties, net of foreign currency transaction loss	—	—	—	—	248
(Loss) Income before provision for income tax (benefit) provision	(267,509)	89,864	114,763	9,722	10,730
Income tax (benefit) provision	(93,405)	33,692	42,507	3,338	3,488
Net (loss) income	$ (174,104)	$ 56,172	$ 72,256	$ 6,384	$ 7,242
(Loss) Earnings per share					
Basic	$ (4.30)	$ 1.43	$ 1.85	$ 0.18	$ 0.25
Diluted	$ (4.30)	$ 1.42	$ 1.85	$ 0.18	$ 0.25
Statement of Cash Flows Data					
Net cash provided by (used in)					
Operating activities	$ 102,716	$ 171,604	$ 110,695	$ 72,089	$ 84,818
Investing activities	(217,347)	(377,172)	(187,324)	(291,963)	(272,991)
Financing activities	114,799	147,239	134,623	214,250	165,028
Effect of Canadian exchange rate	—	—	—	—	(19)
Balance Sheet Data					
Cash and cash equivalents	$ 600	$ 432	$ 58,761	$ 767	$ 301
Restricted cash	—	—	7,350	—	—
Other current assets	19,838	60,647	24,302	14,889	11,085
Property, equipment, net, successful efforts method, net	1,154,546	1,331,659	1,047,030	828,467	595,284
Equity method investment	—	—	—	9,892	—
Other assets	—	—	1,388	881	—
Total assets	$1,174,984	$1,392,738	$1,138,831	$ 854,896	$ 606,670
Current liabilities	$ 28,508	$ 106,852	$ 84,441	$ 60,247	$ 43,625
Long-term debt, net	496,587	391,311	243,347	105,157	42,576
Other long-term liabilities	41,922	120,248	100,548	56,024	53,020
Stockholders' equity	607,967	774,327	710,495	633,468	467,449
Total liabilities and stockholders' equity	$1,174,984	$1,392,738	$1,138,831	$ 854,896	$ 606,670

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 126,000 net acres as of December 31, 2015. We believe our concentrated acreage position 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. 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, 2015, our estimated proved reserves were 166.6 MMBoe. Substantially all of our proved reserves are located in Crockett and Schleicher Counties, Texas. Important characteristics of our proved reserves at December 31, 2015, include:

- 33% oil, 30% NGLs and 37% natural gas;
- 37% proved developed;
- 100% operated;
- Reserve life of approximately 30 years based on 2015 production of 5.5 MMBoe;
- Standardized measure of discounted future net cash flows ("standardized measure") of $460.4 million; and
- PV-10 (non-GAAP) of $504 million.

PV-10 is our estimate of the present value of future net revenues from proved oil, NGL 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 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, 2015, we owned and operated 803 producing oil and gas wells in the Permian Basin. During 2015, we produced 5.5 MMBoe, or 15.2 MBoe/d. Production for 2015 was 34% oil, 31% NGLs and 35% natural gas.

Our financial results depend upon 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 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, NGL and gas consumption. As a result, we cannot accurately predict future oil, NGL 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, prices for NYMEX-WTI have declined from a high of $107.26 per Bbl in June 2014 to as low as $26.55 per Bbl in January 2016. NYMEX-Henry Hub natural gas prices declined from a high of $6.15 per MMBtu in February 2014 to as low as $1.76 per MMBtu in December 2015. If the current depressed oil or natural gas prices persist for a prolonged period or further decline, they will have a material adverse effect on our business, financial condition, results of operations, cash flows and quantities of oil, natural gas and NGL 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, long-term debt, equity 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.

2015 Activity

Our 2015 activity focused on horizontal drilling in the Wolfcamp shale oil resource play in the Midland Basin. We drilled 20, and completed 28, horizontal wells in 2015. In addition, we made a strategic investment in building a large-scale water recycling system, which reduces drilling and completion costs, per-unit lease operating expense and our fresh water use. We plan to continue to develop the Wolfcamp shale in Project Pangea in 2016, although at a materially reduced pace from 2015, subject to commodity prices. Our activities in 2015 included:

- ***Production Growth.*** Production for 2015 totaled 5.5 MMBoe (15.2 MBoe/d), compared to 5 MMBoe (13.8 MBoe/d) in 2014, a 10% increase. Production for 2015 was 34% oil, 31% NGLs and 35% natural gas. We operated an average of one horizontal rig in 2015, drilled a total of 20, and completed 28, horizontal wells. At December 31, 2015, five wells were waiting on completion.

- ***Reserve Growth.*** In 2015, our estimated proved reserves increased 14%, or 20.4 MMBoe, to 166.6 MMBoe from 146.2 MMBoe. Our proved reserves at year-end 2015 were 33% oil, 30% NGLs and 37% natural gas. Reserve growth in 2015 was driven by results in our Wolfcamp shale oil resource play.
- ***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, 2015, we had drilled a total of 16 wells targeting the Wolfcamp A bench, 105 wells targeting the Wolfcamp B bench and 43 wells targeting the Wolfcamp C bench. We have successful wells targeting each of the Wolfcamp benches, and we continued development in 2015.
- ***Installation of Field Infrastructure and Water Recycling Systems.*** Our large, mostly contiguous acreage position and our success in the Wolfcamp shale oil play led us to invest over $110 million in building field infrastructure since 2012. We continued the infrastructure build out in 2015, and now have an extensive network of centralized production facilities, water transportation 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.

Plans for 2016

In March 2016, in response to continued, depressed oil, NGL and gas prices and uncertain market conditions, we announced that we were reducing our capital expenditure budget to a range of $20 million to $80 million in 2016, compared to $151.2 million of actual capital expenditures in 2015. At current commodity prices, we plan to drill six horizontal wells and complete five horizontal wells. We resumed drilling in 2016, and currently have one rig running. We expect to release this rig in the first quarter of 2016. We have the operational flexibility to increase the capital budget in case of a commodity price recovery in 2016 or to further adjust our capital budget downward in response to further commodity price decreases.

Our 2016 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 a sustained, low 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, NGL 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,		
	2015	2014	2013
Revenues (in thousands)			
Oil	$ 82,170	$177,491	$130,971
NGLs	20,437	41,998	28,103
Gas	28,729	39,040	22,228
Total oil, NGL and gas sales	131,336	258,529	181,302
Realized gain (loss) on commodity derivatives	52,489	2,359	(1,048)
Total oil, NGL and gas sales including derivative impact	$183,825	$260,888	$180,254
Production			
Oil (MBbls)	1,882	2,024	1,444
NGLs (MBbls)	1,694	1,461	951
Gas (MMcf)	11,732	9,383	6,177
Total (MBoe)	5,532	5,049	3,424
Total (MBoe/d)	15.2	13.8	9.4
Average prices			
Oil (per Bbl)	$ 43.65	$ 87.69	$ 90.70
NGLs (per Bbl)	12.06	28.74	29.57
Gas (per Mcf)	2.45	4.16	3.60
Total (per Boe)	$ 23.74	$ 51.20	$ 52.95
Realized gain (loss) on commodity derivatives (per Boe)	9.49	0.47	(0.31)
Total including derivative impact (per Boe)	$ 33.23	$ 51.67	$ 52.64
Costs and expenses (per Boe)			
Lease operating	$ 5.24	$ 6.48	$ 5.59
Production and ad valorem taxes	2.00	3.16	3.75
Exploration	0.80	0.76	0.65
General and administrative	5.12	6.36	7.75
Depletion, depreciation and amortization	19.76	21.15	22.48

Oil, NGL and gas sales. Oil, NGL and gas sales for 2015 decreased $127.2 million, or 49%, to $131.3 million from $258.5 million in 2014. The decrease in oil, NGL and gas sales was due to a decrease in average realized commodity prices ($131.3 million), offset by an increase in production volumes ($4.1 million). In 2015, the average price we received for our production, before the effect of commodity derivatives, decreased 54% to $23.74 per Boe, down from $51.20 per Boe in the prior year. Production volumes increased as a result of completing 28 wells in Project Pangea in 2015. We expect oil, NGL and gas sales to continue to decrease in 2016 due to depressed commodity prices and reduced drilling and completion activity.

Oil, NGL and gas sales for 2014 increased $77.2 million, or 43%, to $258.5 million from $181.3 million in 2013. The increase in oil, NGL and gas sales was due to an increase in production volumes ($79.2 million), offset by a decrease in our average realized price ($2 million). Production volumes increased as a result of our continued development in Project Pangea. In 2014, the average price we received for our production, before the effect of commodity derivatives, decreased to $51.20 per Boe from $52.95 per Boe, or a 3% decrease.

Net (loss) income. Net loss for 2015 was $174.1 million, or $4.30 per diluted share, compared to net income of $56.2 million, or $1.42 per diluted share, for 2014. Net loss for 2015 included an impairment loss of $220.2 million, a tax benefit of $93.4 million primarily related to the impairment loss, a realized gain on commodity derivatives of $52.5 million, an unrealized loss on commodity derivatives of $33.2 million, a gain on debt extinguishment of $10.6 million and termination costs of $1.4 million. Net loss for 2015 was primarily due to lower commodity prices, which resulted in a decrease in revenues of $127.2 million and an impairment loss of $220.2 million, partially offset by a change in income taxes of $127.1 million.

Net income for 2014 was $56.2 million, or $1.42 per diluted share, compared to net income of $72.3 million, or $1.85 per diluted share, for 2013. Net income for 2014 included an unrealized gain on commodity derivatives of $42.1 million and a realized gain on commodity derivatives of $2.4 million. Net income for 2014 decreased primarily due to the pretax gain from the sale of our interest in the Wildcat oil pipeline of $90.7 million in 2013 and higher operating expenses as a result of increased production. This was partially offset by an increase in revenues and an increase in gains from our derivative positions.

Oil, NGL and gas production. Production for 2015 totaled 5,532 MBoe (15.2 MBoe/d), compared to 5,049 MBoe (13.8 MBoe/d) in 2014, an increase of 10%. Production for 2015 was 34% oil, 31% NGLs and 35% natural gas, compared to 40% oil, 29% NGLs and 31% natural gas in 2014. The increase in production in 2015 was the result of our continued development of our Permian Basin properties. We expect production to decrease in 2016 due to our reduced drilling and completion activity in response to low commodity prices.

Production for 2014 totaled 5,049 MBoe (13.8 MBoe/d), compared to 3,424 MBoe (9.4 MBoe/d) in 2013, an increase of 47%. Production for 2014 was 40% oil, 29% NGLs and 31% natural gas, compared to 42% oil, 28% NGLs and 30% natural gas in 2013. The increase in production in 2014 was the result of our continued development of our Permian Basin properties.

Impairment of oil and gas properties. 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.

We may incur additional impairments to our oil and natural gas properties in the future if oil and gas prices continue to stay depressed or decline further. The possibility and amount of any future impairment is difficult to predict, and will depend, in part, upon future oil and gas prices, estimates of proved reserves and future cash flows, capital expenditures and production costs. If commodity prices stay depressed or decline further, downward revisions of proved reserves and estimated cash flows may be significant and could result in additional impairment in future periods.

Commodity derivative activities. Realized gains from our commodity derivative activity increased our earnings by $52.5 million for 2015, compared to a realized gain of $2.4 million for 2014 and a realized loss in 2013 of $1 million. Realized gains and losses are derived from the relative movement of commodity prices in relation to the fixed notional pricing in our derivative contracts for the respective years. The unrealized loss on commodity derivatives was $33.2 million for 2015. This is compared to an unrealized gain of $42.1 million for 2014 and an unrealized loss of $4.6 million in 2013. As commodity prices increase or decrease, the fair value of the open portion of those positions decreases or increases, respectively. For 2016, we currently have derivative contracts for 547,500 Bbls of oil at an average price of $51.33 per Bbl, and 6,400,000 MMBtu of natural gas at an average price of $2.60 per MMBtu.

Historically, we have not designated our derivative instruments as cash-flow hedges. We record our open derivative instruments at fair value on our consolidated balance sheets as either unrealized gains or losses on commodity derivatives. We record changes in such fair value in earnings on our consolidated statements of operations under the caption entitled "unrealized (loss) gain on commodity derivatives."

Lease operating expense. Our lease operating expenses ("LOE") decreased $3.7 million, or 11%, for 2015, to $29 million ($5.24 per Boe) from $32.7 million ($6.48 per Boe) for 2014. LOE per Boe in 2015 decreased $1.24, or 19%, from 2014. The decrease in LOE per Boe in 2015 over 2014 was primarily due to a decrease in well repairs, workovers and maintenance, increased efficiency in our water hauling and overall operations and other cost-saving initiatives. We expect LOE per Boe in 2016 to be relatively consistent with 2015 despite lower production volumes, which we expect will be partially offset by lower costs.

Our LOE increased $13.5 million, or 71%, for 2014, to $32.7 million ($6.48 per Boe) from $19.2 million ($5.59 per Boe) for 2013. LOE per Boe in 2014 increased $0.89, or 16%, from 2013. The increase in LOE per Boe in 2014 over 2013 was primarily due to an increase in compressor rental and repair, water hauling and insurance, well repairs, workovers and maintenance, partially offset by a decrease in pumpers and supervision.

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

	Year Ended December 31,						
	2015		2014		Change		
	$MM	Boe	$MM	Boe	$MM	Boe	% Change (Boe)
Compressor rental and repair	$10.2	$1.84	$ 9.6	$1.90	$ 0.6	$(0.06)	(3.2)%
Water hauling and other	9.2	1.66	9.6	1.90	(0.4)	(0.24)	(12.6)
Pumpers and supervision	5.3	0.95	5.0	0.99	0.3	(0.04)	(4.0)
Well repairs, workovers and maintenance	4.3	0.79	8.5	1.69	(4.2)	(0.90)	(53.3)
Total	$29.0	$5.24	$32.7	$6.48	$ (3.7)	$(1.24)	(19.1)%

	Year Ended December 31,						
	2014		2013		Change		
	$MM	Boe	$MM	Boe	$MM	Boe	% Change (Boe)
Compressor rental and repair	$ 9.6	$1.90	$ 5.2	$1.52	$ 4.4	$ 0.38	25.0%
Water hauling and other	9.6	1.90	4.9	1.42	4.7	0.48	33.8
Pumpers and supervision	5.0	0.99	3.6	1.04	1.4	(0.05)	(4.8)
Well repairs, workovers and maintenance	8.5	1.69	5.5	1.61	3.0	0.08	5.0
Total	$32.7	$6.48	$19.2	$5.59	$13.5	$ 0.89	15.9%

Production and ad valorem taxes. Our 2015 production and ad valorem taxes decreased approximately $4.8 million, or 30%, to $11.1 million from $15.9 million for 2014. The decrease in production and ad valorem taxes was primarily the result of a decrease in oil, NGL and gas sales over 2014. Production and ad valorem taxes were approximately 8.4% and 6.2% of oil, NGL and gas sales for the respective periods. Production and ad valorem taxes as a percentage of revenue increased in 2015 due to a refund from the state of Texas for production taxes on natural gas properties of approximately $1 million relating to tax reimbursements in 2014.

Our 2014 production and ad valorem taxes increased approximately $3.1 million, or 24%, to $15.9 million from $12.8 million for 2013. The increase in production and ad valorem taxes was primarily the result of an increase in oil, NGL and gas sales over 2013. Production and ad valorem taxes were approximately 6.2% and 7.1% of oil, NGL and gas sales for the respective periods. Production and ad valorem taxes as a percentage of revenue decreased in 2014 due to a refund from the state of Texas for production taxes on natural gas properties of approximately $1 million relating to tax reimbursements.

Exploration expense. We recorded $4.4 million, $3.8 million and $2.2 million of exploration expense for 2015, 2014 and 2013, respectively. The increase in exploration expense in 2015 was primarily due to the early termination of drilling contracts for $2.2 million, partially offset by lower lease expirations in the current year. Exploration expense for 2014 and 2013 resulted primarily from lease expirations and 3-D seismic data in the Permian Basin.

General and administrative expenses. Our general and administrative expenses ("G&A") decreased $3.8 million, or 12%, to $28.3 million ($5.12 per Boe) for 2015 from $32.1 million ($6.36 per Boe) for 2014. The decrease in G&A and G&A per Boe was primarily due to lower salaries and benefits, share-based compensation and other cost saving initiatives. Share-based compensation for 2015 included a benefit of $0.3 million related to the forfeiture of unvested shares of restricted stock in connection with a reduction in our workforce. Additionally, share-based compensation expense for 2014 included a $1.1 million benefit of forfeited stock awards related to the retirement of one of our executive officers. We expect G&A to continue to decline due to our cost-saving initiatives and the reduction in our workforce.

Our G&A increased $5.6 million, or 21%, to $32.1 million ($6.36 per Boe) for 2014 from $26.5 million ($7.75 per Boe) for 2013. The increase in G&A in 2014 over 2013 was primarily due to an increase in staff and related salaries, benefits and share-based compensation. G&A per Boe decreased in 2014 over 2013 due to higher production as a result of our continued development in Project Pangea.

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

	Year Ended December 31,				Change		
	2015		2014				% Change
	$MM	Boe	$MM	Boe	$MM	Boe	(Boe)
Salaries and benefits	$12.1	$2.19	$15.4	$3.05	$(3.3)	$(0.86)	(28.2)%
Share-based compensation	8.0	1.44	8.2	1.63	(0.2)	(0.19)	(11.7)
Professional fees	2.9	0.52	2.6	0.52	0.3	—	—
Other	5.3	0.97	5.9	1.16	(0.6)	(0.19)	(16.4)
Total	$28.3	$5.12	$32.1	$6.36	$(3.8)	$(1.24)	(19.5)%

	Year Ended December 31,				Change		
	2014		2013				% Change
	$MM	Boe	$MM	Boe	$MM	Boe	(Boe)
Salaries and benefits	$15.4	$3.05	$13.2	$3.85	$ 2.2	$(0.80)	(20.8)%
Share-based compensation	8.2	1.63	5.9	1.72	2.3	(0.09)	(5.2)
Professional fees	2.6	0.52	2.3	0.67	0.3	(0.15)	(22.4)
Other	5.9	1.16	5.1	1.51	0.8	(0.35)	(23.2)
Total	$32.1	$6.36	$26.5	$7.75	$ 5.6	$(1.39)	(17.9)%

Termination costs. In 2015, we recorded $1.4 million in termination costs in connection with a reduction in our workforce.

Depletion, depreciation and amortization expense. Our depletion, depreciation and amortization expense ("DD&A") increased $2.5 million, or 2%, to $109.3 million for 2015, from $106.8 million for 2014. The increase in DD&A in 2015 over 2014 was primarily attributable to an increase in production. Our DD&A per Boe decreased by $1.39, or 7%, to $19.76 per Boe for 2015, compared to $21.15 per Boe for 2014. 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 increased $29.8 million, or 39%, to $106.8 million for 2014, from $77 million for 2013. The increase in DD&A in 2014 over 2013 was primarily attributable to increases in production. Our DD&A per Boe decreased by $1.33, or 6%, to $21.15 per Boe for 2014, compared to $22.48 per Boe for 2013. 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.

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, 2015, 2014 and 2013 (dollars in thousands). Interest expense for 2015 and 2014 includes amortization of loan origination fees and deferred offering costs of $1.6 million and $1.5 million, respectively. The increase in interest expense in 2015 over 2014 was primarily due to increased borrowings under our revolving credit facility. The increase in interest expense in 2014 over 2013 was primarily due to interest payable on the 7% Senior Notes due 2021 (the “Senior Notes”) that were issued in June 2013. We expect our interest expense to remain higher than the prior year period as a result of increased borrowings and higher interest rates under our revolving credit facility, partially offset by interest savings as a result of the repurchase of $19.7 million aggregate face value of our Senior Notes in 2015.

	Year Ended December 31,		
	2015	2014	2013
Interest expense	$ 25,066	$ 21,651	$ 14,084
Weighted average interest rate	5.1%	6.9%	6.8%
Weighted average debt balance	$491,528	$315,575	$205,720

Gain on extinguishment of 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.

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 repurchase additional Senior Notes in the future. The amounts involved in any such transaction, individually or in the aggregate, may be material.

Gain on sale of equity method investment. In October 2013, together with our partner in the Wildcat oil pipeline, we completed the sale of all of the equity interests of Wildcat for a purchase price of $210 million. We recognized a pre-tax gain of $90.7 million related to this transaction, subject to normal post-closing adjustments. In 2014, we recognized post-closing adjustments of $0.2 million.

Income taxes. Our effective income tax rate for 2015, 2014 and 2013 was 34.9%, 37.5% and 37%, respectively. The lower tax rate in 2015, compared to 2014, was a result of a deferred tax asset reversal related to share-based compensation which decreased our effective tax rate by 0.7%. The higher income tax rate in 2014, compared to 2013, was a result of a deferred tax asset reversal related to share-based compensation which increased our effective tax rate by 1.9%.

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 public 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 remain at their current, depressed levels or decline further, our operating cash flows will decrease and our lenders may further reduce our borrowing base, thus limiting the amounts available to fund future capital expenditures. If we are unable to replace our oil, NGL and gas reserves through acquisition, 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, 2015, we were in compliance with all required covenants under our revolving credit facility. If commodity prices remain at their current, depressed levels, or decline further, this may trigger non-compliance with required debt covenants in the future and otherwise adversely impact our ability to operate.

We believe we 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.

Liquidity

We define liquidity as funds available under our revolving credit facility plus year-end net cash and cash equivalents. At December 31, 2015, we had $273 million in borrowings outstanding under the revolving credit facility and $0.6 million in cash and cash equivalents, compared to $150 million and no borrowings outstanding under our revolving credit facility and $0.4 million and $58.8 million in cash and cash equivalents at December 31, 2014, and 2013, respectively. Our liquidity position at December 31, 2015, decreased due to an increase in borrowings under our revolving credit facility. In September 2015, the lenders under our revolving credit facility completed their semi-annual borrowing base redetermination, which reaffirmed the aggregate lender commitments of $450 million. As of December 31, 2014, the borrowing base under our revolving credit facility was $600 million.

The borrowing base under our revolving credit facility is redetermined semi-annually based on our oil, NGL and gas reserves. In April 2015, the borrowing base decreased from $600 million to $525 million. In September 2015, the borrowing base decreased from $525 million to $450 million. The reduction in our borrowing base in 2015 was primarily attributable to a decrease in commodity prices. We expect that our borrowing base will be redetermined in the first quarter or early second quarter of 2016, and the redetermination will result in a material reduction in our borrowing base in the range of 20% to 30%. However, there is no assurance that the decrease will not be higher or lower than our expectation. Additional information regarding our revolving credit facility is included in Note 3. “Long-Term Debt.”

The following table summarizes our liquidity position at December 31, 2015, 2014 and 2013 (in thousands).

	Year Ended December 31,		
	2015	2014	2013
Credit Facility commitments	$ 450,000	$ 450,000	$350,000
Cash and cash equivalents	600	432	58,761
Long-term debt — Credit Facility	(273,000)	(150,000)	—
Undrawn letters of credit	(325)	(325)	(325)
Liquidity	$ 177,275	$ 300,107	$408,436

Working Capital

Our working capital is affected primarily by our cash and cash equivalents balance and our capital spending program. At December 31, 2015, we had a working capital deficit of $8.1 million, compared to a working capital deficit of $45.8 million and working capital surplus of $6 million at December 31, 2014 and 2013, respectively. 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. The change in working capital during 2014 was primarily attributable to the decrease in cash to fund capital expended on our development project offset by changes in fair value of our commodity derivatives. The change in working capital during 2013 was primarily attributable to proceeds from Senior Notes offering, sale of our interest in the Wildcat oil pipeline and an increase in oil, NGL and gas sales, partially offset by increases in accounts payable and accrued liabilities to fund capital expended on our development project. To the extent we operate or end 2016 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,		
	2015	2014	2013
Cash flows provided by operating activities	$ 102,716	$ 171,604	$ 110,695
Cash flows used in investing activities	(217,347)	(377,172)	(187,324)
Cash flows provided by financing activities	114,799	147,239	134,623
Net increase (decrease) in cash and cash equivalents	$ 168	$ (58,329)	$ 57,994

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.

For 2014, our primary sources of cash were from operating activities, financing activities and cash on hand. Approximately $171.6 million of cash from operations and $147.2 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 2014 compared to 2013, primarily due to an increase in capital expenditures of $94.1 million to fund the development of our Wolfcamp shale oil resource play. In 2013, we received proceeds from the sale of the Wildcat pipeline joint venture of $100.8 million, net of our contributions.

For 2013, our primary sources of cash were from operating activities, investing activities and financing activities. Approximately $110.7 million of cash from operations and $134.6 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 2013 compared to 2012, primarily due to proceeds from the sale of the Wildcat oil pipeline joint venture of $100.8 million, net of our contributions. In June 2013, we completed our public offering of $250 million principal amount of 7% Senior Notes due 2021. We received net proceeds from the issuance of the Senior Notes of approximately $243 million and used a portion of the net proceeds from the offering to repay all outstanding borrowings under our revolving credit facility, fund our capital expenditures for the development of our Wolfcamp shale oil resource play and for general working capital needs.

Operating Activities

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

2014 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, NGL and gas sales as a result of lower commodity prices and the timing of receipts and payments of working capital components.

For 2014, our cash flows from operations and available cash were used primarily for drilling and development activities in the Permian Basin. Cash flows from operating activities increased by $60.9 million, or 55%, to $171.6 million in 2014 from $110.7 million in 2013. The increase in cash flows from operating activities in 2014 versus 2013 was primarily due to an increase in oil, NGL and gas sales due to our development project in the Wolfcamp shale oil resource play and the timing of receipts and payments of working capital components, partially offset by an increase in total expenses.

For 2013, our cash flows from operations and available cash were used primarily for drilling and development activities in the Permian Basin. Cash flows from operating activities increased by $38.6 million, or 54%, to $110.7 million in 2013 from $72.1 million in 2012. The increase in cash flows from operating activities in 2013 versus 2012 was primarily due to an increase in oil, NGL and gas sales due to our development project in the Wolfcamp shale oil resource play and the timing of receipts and payments of working capital components, partially offset by an increase in total expenses.

Investing Activities

During the years ended December 31, 2015, 2014 and 2013, we invested $151.2 million, $390.5 million and $296.4 million, respectively, for capital expenditures on oil and natural gas properties. Cash flows used in investing activities was lower in 2015 compared to 2014 primarily due to a reduction in capital expenditures. Our capital expenditures for 2015 were primarily attributable to drilling and development ($139.1 million), infrastructure projects and equipment ($11.4 million) and lease extensions ($0.7 million). Cash used in investing activities also included changes in working capital associated with investing activities ($66.1 million) related to 2014 capital expenditures that were paid in 2015. Cash flows used in investing activities were higher in 2014 compared to 2013, primarily due to an increase in capital expenditures of $94.1 million and proceeds from the sale of our interest in the Wildcat oil pipeline of $100.8 million, net of our contributions in 2013.

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

	Years Ended December 31,		
	2015	2014	2013
Permian Basin	$139,103	$364,046	$249,905
Permian Basin acquisitions	—	—	1,500
Subtotal	139,103	364,046	251,405
East Texas Basin	—	—	—
Exploratory projects	—	—	—
Infrastructure projects, equipment and 3-D seismic	11,422	21,882	38,157
Lease acquisitions and extensions	653	4,578	6,847
Total	$151,178	$390,506	$296,409

Financing Activities

The following is a description of our financing activities in 2015, 2014 and 2013.

- 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 September 2015, the lenders under our revolving credit facility completed their semi-annual borrowing base redetermination, which reaffirmed the aggregate lender commitments of $450 million.

- In May 2014, we entered into an amended and restated credit agreement, which provided for the revolving credit facility in the stated principal amount of $1 billion.
- In June 2013, we completed our public offering of $250 million principal amount of 7% Senior Notes due 2021. 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, and used the net proceeds from the offering to repay all outstanding borrowings under our revolving credit facility, fund our capital expenditures for the development of our Wolfcamp shale oil resource play and for general working capital needs.

We borrowed $272 million under our revolving credit facility in 2015, compared to $353.9 million and $129.9 million in 2014 and 2013, respectively. We repaid a total of $149 million, $203.9 million and $235.9 million of amounts outstanding under our revolving credit facility for 2015, 2014 and 2013, respectively.

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 $450 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 borrowing base will be redetermined in the first quarter or early second quarter of 2016, and that the redetermination will result in a material reduction in our borrowing base in the range of 20% to 30%. However, there is no assurance that the decrease will not be higher or lower than our expectation. Additionally, in connection with the upcoming redetermination, we expect an increase in the applicable margin rates used to determine the interest on our outstanding borrowings under our revolving credit facility.

The maturity date under our revolving credit facility is May 7, 2019. Borrowings bear interest based on the agent bank's prime rate plus an applicable margin ranging from 0.50% to 1.50%, or the sum of the London Interbank Offered Rate ("LIBOR") rate plus an applicable margin ranging from 1.50% to 2.50%. Margins vary based on the borrowings outstanding compared to the borrowing base. In addition, we pay an annual commitment fee ranging from 0.375% to 0.50% of unused borrowings available under our revolving credit facility. Margins vary based on the borrowings outstanding compared to the borrowing base.

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

We had outstanding borrowings of $273 million and $150 million under our revolving credit facility at December 31, 2015 and 2014, respectively. The weighted average interest rate applicable to borrowings under our revolving credit facility at December 31, 2015, was 2.2%. We also had outstanding unused letters of credit under our revolving credit facility totaling $0.3 million at December 31, 2015, 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 80% of the total value of all oil and gas properties of the Company and its subsidiaries.

Covenants

Our revolving credit facility contains two principal financial covenants:

- a consolidated modified current ratio covenant (as defined in the revolving credit facility) 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, and
- a consolidated interest coverage ratio covenant (as defined in the revolving credit facility) that requires us to maintain a ratio of consolidated EBITDAX to interest of not less than 2.5 to 1.0 as of the last day of any fiscal quarter.

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 the 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 the 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. We expect that our borrowing base will be redetermined in the first quarter or early second quarter of 2016, and that the redetermination will result in a material reduction in our borrowing base in the range of 20% to 30%. However, there is no assurance that the decrease will not be higher or lower than our expectation.

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.

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

On and after June 15, 2016, we may redeem some or all of the Senior Notes at specified redemption prices, plus accrued and unpaid interest to the redemption date. Before June 15, 2016, we may redeem up to 35% of the Senior Notes at a redemption price of 107% of the principal amount, plus accrued and unpaid interest to the redemption date, with the proceeds of certain equity offerings. In addition, before June 15, 2016, we may redeem some or all of the Notes for cash at a redemption price equal to 100% of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. If we sell certain of our assets or experience specific kinds of changes of control, we may be required to offer to purchase the Senior Notes from holders. 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.

The Indenture restricts our ability, among other things, to (i) sell certain assets, (ii) pay distributions on, redeem or repurchase, equity interests, (iii) incur additional debt, (iv) make certain investments, (v) enter into transactions with affiliates, (v) incur liens and (vi) merge or consolidate with another company. These restrictions are subject to a number of important exceptions and qualifications. If at any time the Senior Notes are rated investment grade by both Moody's Investors Service and Standard & Poor's Ratings Services and no default (as defined in the Indenture) has occurred and is continuing, many of these restrictions will terminate. The Indenture contains customary events of default.

At December 31, 2015, 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, 2015, our contractual obligations include 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 40,000 square feet and extended the term to March 31, 2020.

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, 2015, 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, 2015. This estimate assumes the maximum potential bonus for 2016 is earned by each executive officer during 2016.

The following table summarizes these commitments as of December 31, 2015 (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)	$273,000	$ —	$ —	$273,000	$ —
Senior Notes(2)	230,320	—	—	—	230,320
Operating lease obligations(3)	4,121	957	1,942	1,222	—
Asset retirement obligations(4)	10,143	—	—	—	10,143
Employment agreements with executive officers	6,300	6,300	—	—	—
Total	$523,884	$ 7,257	$1,942	$274,222	$240,463

(1) Credit agreement matures on May 7, 2019.
(2) 7% Senior Notes due 2021.
(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.

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, 2015, 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 depletion, depreciation and amortization expense, 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, 2015, 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, 2015, 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, NGL and natural gas reserves. Depletion expense for our oil and gas properties is determined using our estimates of proved oil, NGL 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

Unrealized gains and losses 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. 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 values 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. Realized gains and losses are also included in income (expense) on our consolidated statements of operations.

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 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, 2015, 2014 and 2013, we recognized an unrealized loss of $33.2 million, an unrealized gain of $42.1 million and an unrealized loss of $4.6 million, respectively.

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. 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 do not currently have a valuation allowance on our federal net operating loss carryforwards.

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 general and administrative expenses, 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 Black-Scholes option price model to measure the fair value of stock options, (ii) the closing stock price on the date of grant for the fair value of restricted stock awards, including performance-based awards, and (iii) the Monte Carlo simulation method for the fair value of market-based awards.

Equity Method Investments

For investments in which we have the ability to exercise significant influence but do not have control, we follow the equity method of accounting. In September 2012, we entered into a joint venture to build an oil pipeline in Crockett and Reagan Counties, Texas, which is used to transport our oil to market. In October 2013, we completed the sale of the joint venture. As of December 31, 2015 we have no investments accounted for under the equity method. See Note 2 to our consolidated financial statements in this report for additional information regarding our equity method investment.

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, 2015, 2014 or 2013. 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, 2015, 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. ***QUANTITATIVEAND 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 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 depletion, depreciation and amortization expense, 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, 2015, 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, 2015, 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, NGL and natural gas reserves.

We expect that further or sustained oil and gas prices will not only decrease our revenues, but will also reduce the amount of oil and gas that we can produce economically and therefore lower our oil and gas reserves. The continued significant decline in oil and natural gas prices increases the uncertainty as to the impact of commodity prices on our estimated proved reserves. A decrease of 10% or 25% in the oil, NGL and gas prices used in our reserve report as of December 31, 2015, holding production and development costs constant, would result in:

- a decrease in our PV-10 as of December 31, 2015 of 27% and 49%, respectively,
- a decrease in our total proved reserves of 36% and 64%, respectively, and
- a decrease in our proved undeveloped reserves of 56% and 98%, respectively.

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, NGL and natural gas reserves. A hypothetical 10% decline in our December 31, 2015, estimated proved reserves would have increased our depletion expense by approximately $2.5 million for the year ended December 31, 2015.

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, 2015, the NYMEX WTI spot price averaged $48.84 per barrel and ranged from a low of $34.73 per barrel to a high of $61.43 per barrel. In the year ended December 31, 2014, the

NYMEX WTI spot price averaged $92.94 per barrel and ranged from a low of $53.27 per barrel to a high of $107.26 per barrel.

In the year ended December 31, 2015, the Henry Hub natural gas spot price averaged $2.63 per MMBtu and ranged from a low of $1.76 per MMBtu to a high of $3.23 per MMBtu. In the year ended December 31, 2014, the Henry Hub natural gas spot price averaged $4.28 per MMBtu and ranged from a low of $3.47 per MMBtu to a high of $6.15 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 income (expense) on our consolidated statements of operations as they occur.

The table below summarizes our commodity derivatives positions outstanding at December 31, 2015.

Commodity and Period	Contract Type	Volume Transacted	Contract Price
Crude Oil			
January 2016 — December 2016	Swap	500 Bbls/d	$62.50/Bbl
January 2016 — December 2016	Swap	250 Bbls/d	$62.55/Bbl
January 2016 — June 2016	Swap	500 Bbls/d	$40.25/Bbl
January 2016 — June 2016	Swap	1,000 Bbls/d	$40.00/Bbl
Natural Gas			
March 2016 — December 2016	Swap	100,000 MMBtu/month	$2.91/MMBtu
March 2016 — December 2016	Swap	100,000 MMBtu/month	$2.95/MMBtu

After December 31, 2015, we entered into natural gas swaps covering 400,000 MMBtu per month at an average price of $2.45/MMBtu for February 2016 through March 2017, and natural gas collars covering 200,000 MMBtu per month with a floor price of $2.30/MMBtu and a ceiling price of $2.60/MMBtu for April 2017 through December 2017.

At December 31, 2015, the fair value of our open derivative contracts was an asset of approximately $6.7 million, compared to an asset of $40 million at December 31, 2014.

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 the revolving credit facility is used as collateral for our commodity derivatives.

Unrealized gains and losses, 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 other income (expense) on our consolidated statements of operations. We estimate the fair values 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. Realized gains and losses are also included in other income (expense) on our consolidated statements of operations.

For the years ended December 31, 2015, 2014 and 2013, we recognized an unrealized loss of $33.2 million, an unrealized gain of $42.1 million and an unrealized loss of $4.6 million, respectively. A hypothetical 10% increase in the NYMEX floating prices would have resulted in a $2.7 million decrease in the fair value recorded of our commodity derivative positions on our balance sheet at December 31, 2015, and a corresponding increase to the unrealized loss on commodity derivatives on our statement of operations for the year ended December 31, 2015.

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 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, 2015, 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, 2015, 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 used in estimating our recognized impairment loss represents a nonrecurring Level 3 measurement. See Note 7 to our consolidated financial statements in this report for the significant inputs and methodology related to the Level 3 measurement.

ITEM 8. *FINANCIALSTATEMENTS AND SUPPLEMENTARY DATA*

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

ITEM 9. *CHANGESIN 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. *CONTROLSAND PROCEDURES*

Disclosure Controls and Procedures

Our management, with the participation of our President and 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, 2015. Based on this evaluation, our President and

Chief Executive Officer and Chief Financial Officer have concluded that, as of December 31, 2015, 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 President and 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, 2015. Hein & Associates LLP ("Hein"), our independent registered public accounting firm, also attested to, and reported on, our internal control over financial reporting. Management's report and Hein'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, 2015, 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. ***OTHERINFORMATION***

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 2016 annual meeting of stockholders to be filed with the SEC within 120 days of December 31, 2015, which is incorporated herein by reference. Additional information regarding our corporate governance guidelines as well as the complete texts of our Code of Conduct and the charters of our Audit Committee and our Compensation and Nominating Committee 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 2016 annual meeting of stockholders to be filed with the SEC within 120 days of December 31, 2015, 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 2016 annual meeting of stockholders to be filed with the SEC within 120 days of December 31, 2015, 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 2016 annual meeting of stockholders to be filed with the SEC within 120 days of December 31, 2015, 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 2016 annual meeting of stockholders to be filed with the SEC within 120 days of December 31, 2015, 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.

See "Index to Exhibits" on page 74 for a description of the exhibits filed as part of this report.

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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.

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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 2015 estimated proved reserves by 2015 production of 5.5 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:

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

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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, Chief Executive Officer and President

Date: March 4, 2016

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 4, 2016.

Signature	Title
/s/ J. Ross Craft J. Ross Craft	Chairman of the Board, Chief Executive Officer, President (Principal Executive Officer)
/s/ Sergei Krylov Sergei Krylov	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ Uma L. Datla Uma L. Datla	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 H. Brandi James H. Brandi	Director
/s/ James C. Crain James C. Crain	Director
/s/ Bryan H. Lawrence Bryan H. Lawrence	Director
/s/ Sheldon B. Lubar Sheldon B. Lubar	Director
/s/ Christopher J. Whyte Christopher J. Whyte	Director

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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, 2015. 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, 2015, our internal control over financial reporting is effective based on those criteria.

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

By: /s/ Sergei Krylov
Sergei Krylov
Executive Vice President and Chief Financial Officer

Fort Worth, Texas
March 4, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
Approach Resources Inc.

We have audited Approach Resources, Inc. and subsidiaries' (collectively, the "Company") internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, 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.

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 *(a)* pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; *(b)* 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 *(c)* 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.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Approach Resources, Inc. and subsidiaries as of December 31, 2015 and 2014, and the related consolidated statements of operations, changes in stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2015 and our report dated March 4, 2016, expressed an unqualified opinion.

*/s/ **HEIN** & ASSOCIATES LLP*
Dallas, Texas
March 4, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
Approach Resources Inc.

We have audited the accompanying consolidated balance sheets of Approach Resources Inc. and subsidiaries (collectively, the "Company") as of December 31, 2015 and 2014, and the related consolidated statements of operations, changes in stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2015. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

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, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013, and our report dated March 4, 2016, expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

*/s/ **HEIN** & ASSOCIATES LLP*
Dallas, Texas
March 4, 2016

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Approach Resources Inc. and Subsidiaries

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

	December 31, 2015	December 31, 2014
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 600	$ 432
Accounts receivable:		
Joint interest owners	142	132
Oil, NGL and gas sales	11,747	19,635
Unrealized gain on commodity derivatives	6,737	39,951
Prepaid expenses and other current assets	1,212	929
Total current assets	20,438	61,079
PROPERTIES AND EQUIPMENT:		
Oil and gas properties, at cost, using the successful efforts method of accounting	1,853,781	1,708,278
Furniture, fixtures and equipment	5,628	5,561
Total oil and gas properties and equipment	1,859,409	1,713,839
Less accumulated depletion, depreciation and amortization	(704,863)	(382,180)
Net oil and gas properties and equipment	1,154,546	1,331,659
Total assets	$1,174,984	$1,392,738
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 10,799	$ 33,336
Oil, NGL and gas sales payable	4,245	8,536
Deferred income taxes — current	—	14,242
Accrued liabilities	13,464	50,738
Total current liabilities	28,508	106,852
NON-CURRENT LIABILITIES:		
Senior secured credit facility, net	270,748	147,072
Senior notes, net	225,839	244,239
Deferred income taxes	31,779	110,677
Asset retirement obligations	10,143	9,571
Total liabilities	567,017	618,411
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, 90,000,000 shares authorized, 40,788,705 and 39,814,199 issued and outstanding, respectively	408	399
Additional paid-in capital	580,623	572,888
Retained earnings	26,936	201,040
Total stockholders' equity	607,967	774,327
Total liabilities and stockholders' equity	$1,174,984	$1,392,738

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, 2015	2014	2013
REVENUES:			
Oil, NGL and gas sales	$ 131,336	$ 258,529	$ 181,302
EXPENSES:			
Lease operating	28,972	32,701	19,152
Production and ad valorem taxes	11,085	15,934	12,840
Exploration	4,439	3,831	2,238
General and administrative(1)	28,341	32,104	26,524
Termination costs	1,436	—	—
Impairment of oil and gas properties	220,197	—	—
Depletion, depreciation and amortization	109,319	106,802	76,956
Total expenses	403,789	191,372	137,710
OPERATING (LOSS) INCOME	(272,453)	67,157	43,592
OTHER:			
Interest expense, net	(25,066)	(21,651)	(14,084)
Gain on debt extinguishment	10,563	—	—
Equity in (losses) earnings of investee	—	(181)	156
Gain on sale of equity method investment	—	—	90,743
Realized gain (loss) on commodity derivatives	52,489	2,359	(1,048)
Unrealized (loss) gain on commodity derivatives	(33,214)	42,113	(4,596)
Other income	172	67	—
(LOSS) INCOME BEFORE INCOME TAX (BENEFIT) PROVISION	(267,509)	89,864	114,763
INCOME TAX (BENEFIT) PROVISION:			
Current	(265)	(25)	429
Deferred	(93,140)	33,717	42,078
NET (LOSS) INCOME	$ (174,104)	$ 56,172	$ 72,256
(LOSS) EARNINGS PER SHARE:			
Basic	$ (4.30)	$ 1.43	$ 1.85
Diluted	$ (4.30)	$ 1.42	$ 1.85
WEIGHTED AVERAGE SHARES OUTSTANDING:			
Basic	40,464,283	39,407,733	38,997,815
Diluted	40,464,283	39,419,865	39,019,149
(1) Includes non-cash share-based compensation expense as follows:			
	7,954	8,247	5,901

See accompanying notes to these consolidated financial statements.

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Approach Resources Inc. and Subsidiaries

Consolidated Statements of Changes in Stockholders' Equity for the Years Ended December 31, 2013, 2014 and 2015 (In thousands, except shares and per-share amounts)

	Common Stock		Additional Paid-in Capital	Retained Earnings	Total
	Shares	Amount			
BALANCES, January 1, 2013	38,829,368	$ 388	$560,468	$ 72,612	$ 633,468
Issuance of common stock upon exercise of options	3,750	—	58	—	58
Issuance of common shares to directors for compensation	24,317	—	630	—	630
Restricted stock issuance, net of cancellations	245,262	2	(2)	—	—
Share-based compensation expense	—	—	5,271	—	5,271
Surrender of restricted shares for payment of income taxes	(54,998)	—	(1,188)	—	(1,188)
Net income	—	—	—	72,256	72,256
BALANCES, December 31, 2013	39,047,699	$ 390	$565,237	$ 144,868	$ 710,495
Issuance of common shares to directors for compensation	40,898	1	748	—	749
Restricted stock issuance, net of cancellations	782,708	8	(8)	—	—
Share-based compensation expense	—	—	7,498	—	7,498
Surrender of restricted shares for payment of income taxes	(57,106)	—	(587)	—	(587)
Net income	—	—	—	56,172	56,172
BALANCES, December 31, 2014	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 loss	—	—	—	(174,104)	(174,104)
BALANCES, December 31, 2015	40,788,705	$ 408	$580,623	$ 26,936	$ 607,967

See accompanying notes to these consolidated financial statements.

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Approach Resources Inc. and Subsidiaries

Consolidated Statements of Cash Flows
(In thousands, except shares and per-share amounts)

	For the Years Ended December 31, 2015	2014	2013
OPERATING ACTIVITIES:			
Net (loss) income	$(174,104)	$ 56,172	$ 72,256
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Depletion, depreciation and amortization	109,319	106,802	76,956
Impairment of oil and gas properties	220,197	—	—
Amortization of debt issuance costs	1,561	1,546	1,048
Gain on debt extinguishment	(10,563)	—	—
Unrealized loss (gain) on commodity derivatives	33,214	(42,113)	4,596
Gain on sale of equity method investment	—	—	(90,743)
Exploration expense	1,836	3,831	2,238
Share-based compensation expense	7,954	8,247	5,901
Deferred income tax (benefit) expense	(93,140)	33,717	42,078
Equity in losses (earnings) of investee	—	181	(156)
Other non-cash items	(172)	(179)	—
Changes in operating assets and liabilities:			
Accounts receivable	7,878	3,262	(10,239)
Prepaid expenses and other current assets	(325)	(179)	(45)
Accounts payable	964	(2,262)	1,478
Oil, NGL and gas sales payable	(4,291)	2,435	1,141
Accrued liabilities	2,388	144	4,186
Cash provided by operating activities	102,716	171,604	110,695
INVESTING ACTIVITIES:			
Additions to oil and gas properties	(151,178)	(390,506)	(296,409)
Proceeds from sale of equity method investment, net of contributions	—	(181)	100,791
Change in restricted cash	—	7,350	(7,350)
Additions to furniture, fixtures and equipment, net	(67)	(3,024)	(429)
Change in working capital related to investing activities	(66,102)	9,189	16,073
Cash used in investing activities	(217,347)	(377,172)	(187,324)
FINANCING ACTIVITIES:			
Borrowings under credit facility	272,000	353,921	129,950
Repayment of amounts outstanding under credit facility	(149,000)	(203,921)	(235,950)
Proceeds from issuance of senior notes	—	—	242,824
Extinguishment of senior notes	(8,722)	—	—
Tax withholdings related to restricted stock	(210)	(587)	(1,188)
Proceeds from issuance of common stock upon exercise of stock options	—	—	58
Loan origination fees	—	(2,174)	(1,071)
Change in working capital related to financing activities	731	—	—
Cash provided by financing activities	114,799	147,239	134,623
CHANGE IN CASH AND CASH EQUIVALENTS	168	(58,329)	57,994
CASH AND CASH EQUIVALENTS, beginning of year	432	58,761	767
CASH AND CASH EQUIVALENTS, end of year	$ 600	$ 432	$ 58,761
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash paid for income taxes	$ —	$ 404	$ —
Cash paid for interest	$ 23,634	$ 20,232	$ 12,392
SUPPLEMENTAL DISCLOSURE OF NON-CASH TRANSACTION:			
Acquisition of oil and gas properties	$ —	$ 510	$ 132
Asset retirement obligations capitalized	$ 151	$ 898	$ 584

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 income 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, 2015	December 31, 2014
Mineral interests in properties:		
Unproved leasehold costs	$ 37,853	$ 46,240
Proved leasehold costs	44,122	42,409
Wells and related equipment and facilities	1,753,649	1,592,477
Support equipment	9,545	8,518
Uncompleted wells, equipment and facilities	8,612	18,634
Total costs	1,853,781	1,708,278
Less accumulated depreciation, depletion and amortization	(702,139)	(379,892)
Net capitalized costs	$ 1,151,642	$ 1,328,386

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

Approach Resources Inc. and Subsidiaries

Notes to Consolidated Financial Statements — (Continued)

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, 2015 or 2014. 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, 2015, 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 $108.8 million, $106.2 million and $76.5 million for the years ended December 31, 2015, 2014 and 2013, 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. 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. We recorded no impairment of our proved properties for the years ended December 31, 2014 and 2013.

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. Certain leases that we consider non-core to our development of Project Pangea were impaired during the year ended December 31, 2015, as we do not plan to develop them in the current commodity price environment. 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.

Approach Resources Inc. and Subsidiaries

Notes to Consolidated Financial Statements — (Continued)

On the sale of an entire interest in an unproved property for cash or cash equivalent, 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.

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 $563,000, $588,000 and $502,000 for the years ended December 31, 2015, 2014 and 2013, respectively.

Equity Method Investment

For investments in which we have the ability to exercise significant influence but do not have control, we follow the equity method of accounting. In September 2012, we entered into a joint venture to build an oil pipeline in Crockett and Reagan Counties, Texas, which is used to transport our oil to market. In October 2013, we completed the sale of the joint venture. As of December 31, 2015, we have no investments that are accounted for under the equity method. See Note 2 for equity method investment disclosures.

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, 2015 and 2014. 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 in the consolidated statement of income.

Based on our analysis, we did not have any uncertain tax positions as of December 31, 2015 or 2014. 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 2012 and forward and Texas income and margin tax returns for tax years 2012 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 do not currently have a valuation allowance on our federal net operating loss carryforwards.

Derivative Activity

We record our open derivative instruments at fair value on our consolidated balance sheets as either unrealized gains or losses on commodity derivatives. We record changes in such fair value in earnings on our consolidated statements of operations under the caption entitled “unrealized (loss) gain on commodity derivatives.”

Although we have not designated our derivative instruments as cash-flow hedges, we use those instruments to reduce our exposure to fluctuations in commodity prices related to our natural gas and oil production. Unrealized gains and losses, 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. Realized gains and losses are also included in income (expense) on our consolidated statements of operations.

Accrued Liabilities

The following is a summary of our accrued liabilities at December 31, 2015 and 2014 (in thousands):

	2015	2014
Capital expenditures accrual	$ 3,476	$43,870
Operating expenses and other	9,988	6,868
Total	$13,464	$50,738

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, 2015, 2014 and 2013.

Share-Based Compensation

We measure and record compensation expense for all 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 expense 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,		
	2015	2014	2013
Income (numerator):			
Net (loss) income — basic	$ (174,104)	$ 56,172	$ 72,256
Weighted average shares (denominator):			
Weighted average shares — basic	40,464,283	39,407,733	38,997,815
Dilution effect of share-based compensation, treasury method	—(1)	12,132	21,334
Weighted average shares — diluted	40,464,283	39,419,865	39,019,149
Net (loss) income per share:			
Basic	$ (4.30)	$ 1.43	$ 1.85
Diluted	$ (4.30)	$ 1.42	$ 1.85

(1) Approximately 39,000 options to purchase our common stock were excluded from this calculation because they were antidilutive for the year ended December 31, 2015.

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, NGL 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, 2015 or 2014. Accounts receivable related to oil, NGL and gas sales includes $4.8 million from realized gains on commodity derivatives at December 31, 2015 and 2014.

Oil, NGL and Gas Sales Payable. Oil, NGL and gas sales payable represents amounts collected from purchasers for oil, NGL 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 expense on our consolidated statements of operations.

Approach Resources Inc. and Subsidiaries

Notes to Consolidated Financial Statements — (Continued)

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, 2015, sales to JP Energy Development, LP ("JP Energy") and DCP Midstream, LP ("DCP") accounted for approximately 63% and 36%, respectively, of our total sales. As of December 31, 2015, we had dedicated all of our oil production from northern Project Pangea and Pangea West through 2022 to JP Energy. In addition, as of December 31, 2015, we had contracted to sell all of our NGLs and natural gas production from Project Pangea to DCP through January 2023. For the year ended December 31, 2014, sales to DCP and JP Energy accounted for approximately 30% and 69%, respectively of our total sales. For the year ended December 31, 2013, sales to Wildcat Permian Services, LLC, DCP and JP Energy Permian, LLC accounted for approximately 30%, 27% and 23%, 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 ("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 application not permitted. In July 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 not determined which transition method we will use and are continuing to evaluate our existing revenue recognition policies to determine whether any of our contracts will be affected by the new requirements.

In April 2015, FASB issued an accounting standards update for "Interest — Imputation of Interest," which simplifies the presentation of debt issuance costs. This accounting standard update requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. This new update is effective for financial statements issued for fiscal years beginning after December 15, 2015 (and interim periods within those fiscal years), with early adoption permitted and retrospective application required. We adopted this accounting standard update during the second quarter. The adoption of this new accounting standard update resulted in a reclassification of debt issuance costs from Other assets to Senior secured credit facility, net and Senior notes, net. See Note 3 "Long-Term Debt" for disclosure of debt issuance costs. Adoption of this accounting standard update did not impact our consolidated statements of operations or cash flows.

In September 2015, FASB issued an accounting standards update for "Business Combinations," which requires that an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. This new update is effective for financial statements issued for fiscal years beginning after December 15, 2015 (and interim periods within those fiscal years). This new guidance will be adopted prospectively in the first quarter of 2016. The Company is evaluating the impact of this new guidance and does not expect it to have a significant impact on the consolidated financial statements.

In November 2015, FASB issued an accounting standards update for "Income Taxes," which simplifies the presentation of deferred income taxes. This accounting standard update requires that deferred income taxes be classified as noncurrent in the balance sheet. This new update is effective for financial statements issued for fiscal years beginning after December 15, 2016 (and interim periods within those fiscal years), with early adoption permitted and allows prospective or retrospective application. We adopted this accounting standard update prospectively as of December 31, 2015. At December 31, 2015, we had no deferred tax assets or liabilities classified as current, compared to a current deferred tax liability of $14.2 million as of December 31, 2014. Adoption of this accounting standard update did not impact our consolidated statements of operations or cash flows.

2. Equity Method Investment

In September 2012, we entered into a joint venture to build an oil pipeline in Crockett and Reagan Counties, Texas, which is used to transport our oil to market. In October 2012, we made an initial contribution of $10 million to the joint venture for pipeline and facilities construction. In 2013, we contributed $8.3 million to the equity joint venture for pipeline and facilities construction prior to its sale in October 2013. Our contributions were recorded at cost and were included in noncurrent assets, "Equity method investment," on our consolidated balance sheets and in investing activities, "Contribution to equity method investment," on our consolidated statements of cash flows. Our share of the investee earnings was recorded on our consolidated statements of operations for the years ended December 31, 2014, 2013 and 2012. In October 2013, we completed the sale of the joint venture, and net proceeds to Approach at closing totaled approximately $109.1 million, after deducting our share of transactional costs paid at closing. We recognized a pre-tax gain of $90.7 million related to this transaction, subject to normal post-closing adjustments, in 2013. Of the $109.1 million in proceeds, $7.4 million was restricted pursuant to an escrow agreement and recorded as restricted cash at December 31, 2013. The escrow agreement terminated on June 1, 2014, and the cash held in escrow was subsequently released. We incurred $0.2 million in post-closing working capital adjustments during the year ended December 31, 2014.

3. Long-Term Debt

The following table provides a summary of our long-term debt at December 31, 2015, and December 31, 2014 (in thousands).

	December 31, 2015	December 31, 2014
Senior secured credit facility:		
Outstanding borrowings	$ 273,000	$ 150,000
Debt issuance costs	(2,252)	(2,928)
Senior secured credit facility, net	270,748	147,072
Senior notes:		
Principal	230,320	250,000
Debt issuance costs	(4,481)	(5,761)
Senior notes, net	225,839	244,239
Total long-term debt	$ 496,587	$ 391,311

Approach Resources Inc. and Subsidiaries

Notes to Consolidated Financial Statements — (Continued)

Senior Secured Credit Facility

At December 31, 2015, the borrowing base and aggregate lender commitments under our amended and restated senior secured credit facility (the "Credit Facility") were $450 million, with maximum commitments from the lenders of $1 billion. The Credit Facility has a maturity date of May 7, 2019. The borrowing base is redetermined semi-annually based on our oil, NGL and gas reserves. We, or the lenders, can each request one additional borrowing base redetermination each calendar year.

Borrowings under the Credit Facility bear interest based on the agent bank's prime rate plus an applicable margin ranging from 0.50% to 1.50%, or the sum of the LIBOR rate plus an applicable margin ranging from 1.50% to 2.50%. In addition, we pay an annual commitment fee ranging from 0.375% to 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 $273 million of outstanding borrowings under the Credit Facility at December 31, 2015, compared to $150 million of outstanding borrowings at December 31, 2014. The weighted average interest rate applicable to borrowings under the Credit Facility at December 31, 2015, was 2.2%. We also had outstanding unused letters of credit under our Credit Facility totaling $0.3 million at December 31, 2015 and 2014, 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 maintain liens covering the oil and gas properties of the Company and its subsidiaries representing at least 80% of the total value of all oil and gas properties of the Company and its subsidiaries.

Covenants

The Credit Facility contains two principal financial covenants:

- a consolidated modified current ratio covenant (as defined in the Credit Facility) 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, and
- a consolidated interest coverage ratio covenant (as defined in the Credit Facility) that requires us to maintain a ratio of consolidated EBITDAX to interest of not less than 2.5 to 1.0 as of the last day of any fiscal quarter.

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.

Approach Resources Inc. and Subsidiaries

Notes to Consolidated Financial Statements — (Continued)

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. 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, 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.

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

On and after June 15, 2016, we may redeem some or all of the Senior Notes at specified redemption prices, plus accrued and unpaid interest to the redemption date. Before June 15, 2016, we may redeem up to 35% of the Senior Notes at a redemption price of 107% of the principal amount, plus accrued and unpaid interest to the redemption date, with the proceeds of certain equity offerings. In addition, before June 15, 2016, we may redeem some or all of the Notes for cash at a redemption price equal to 100% of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. If we sell certain of our assets or experience specific kinds of changes of control, we may be required to offer to purchase the Senior Notes from holders. 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 a 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 credit facility, in each case, which resulted in such restricted subsidiary's obligation to guarantee the notes.

The Indenture restricts our ability, among other things, to (i) sell certain assets, (ii) pay distributions on, redeem or repurchase, equity interests, (iii) incur additional debt, (iv) make certain investments, (v) enter into transactions with affiliates, (vi) incur liens and (vii) merge or consolidate with another company. These restrictions are subject to a number of important exceptions and qualifications. If at any time the Senior Notes are rated investment grade by both Moody's Investors Service and Standard & Poor's Ratings Services and no default (as defined in the Indenture) has occurred and is continuing, many of these restrictions will terminate. The Indenture contains customary events of default.

On December 15, 2015, we made a semi-annual interest payment of $8.6 million.

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, 2015, we were in compliance with all of our covenants, and there were no existing defaults or events of default, under our debt instruments.

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 current oil and gas prices. In connection with the reduction, we incurred $1.4 million in expenses, which is recorded in termination costs on our consolidated statements of operations. As of December 31, 2015, $0.4 million in termination costs is recorded in current liabilities 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 is recorded in general and administrative expense on our consolidated statements of operations.

5. Share-Based Compensation

In June 2007, the 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. Under a Third Amendment to the 2007 Plan effective June 2, 2015, the maximum number of shares of common stock available for the grant of awards under the 2007 Plan after June 2, 2015, is 3,625,000. Awards of any stock options are to be priced at not less than the fair market value at the date of the grant. The vesting period of any stock award is to be determined by the board or an authorized committee at the time of the grant. The term of each stock option is to be fixed at the time of grant and may not exceed 10 years. Shares issued upon stock options exercised are issued as new shares.

Share-based compensation expense amounted to $8.0 million, $8.2 million and $5.9 million for the years ended December 31, 2015, 2014 and 2013, respectively. Such amounts represent the estimated fair value of stock awards for which the requisite service period elapsed during those periods. Included in share-based compensation expense in 2014 and 2013 is a benefit of $1.1 million and $1 million, respectively, for forfeited stock awards related to the retirement of two of our executive officers. Share-based compensation expense for the years ended December 31, 2015, 2014 and 2013, included $735,000, $749,000 and $630,000, respectively, related to grants to nonemployee directors.

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Stock Options

There were no stock option grants during the years ended December 31, 2015, 2014 and 2013. As of December 31, 2015, 38,525 options were fully vested and outstanding with a weighted average exercise price of $12.00 and a weighted average remaining contractual term of 1.86 years. There were no options exercised during the years ended December 31, 2015 and 2014. The intrinsic value of the options exercised during the year ended December 31, 2013 was $35,000. There was no tax benefit recognized related to the stock option exercises in the year ended December 31, 2013.

Nonvested Shares

Share grants totaling 1,278,329 shares, 992,919 shares and 377,379 shares with an approximate aggregate fair market value of $6.2 million, $14.4 million and $8.6 million at the time of grant were granted to employees during the years ended December 31, 2015, 2014 and 2013, respectively. Included in the share grants for 2015, 2014 and 2013, are 724,249 shares, 245,157 shares and 183,672 shares, respectively, awarded to our executive officers. The aggregate fair market value of these shares on the grant date was $4.5 million, $4.5 million and $4.4 million, respectively, to be expensed over a remaining service period of approximately two years, subject to certain performance restrictions.

A summary of the status of nonvested shares for the years ended December 31, 2015, 2014 and 2013, is presented below:

	Shares	Weighted Average Grant-Date Fair Value
Nonvested at January 1, 2013	753,079	22.35
Granted	377,379	22.77
Vested	(299,110)	18.79
Canceled	(132,117)	24.47
Nonvested at December 31, 2013	699,231	23.70
Granted	992,919	14.48
Vested	(400,429)	20.18
Canceled	(169,311)	25.57
Nonvested at December 31, 2014	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

As of December 31, 2015, unrecognized compensation expense related to the nonvested shares amounted to $7.9 million, which will be recognized over a remaining service period of three years.

Subsequent Restricted Share Award

Subsequent to December 31, 2015, 1,100,543 cash settled shares, subject to certain performance conditions, and 550,272 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 shares and TSR shares on the grant date was approximately $1 million and $0.3 million, respectively, to be expensed over a remaining service period of approximately 3.5 years.

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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 $404,000, $310,000 and $279,000 during the years ended December 31, 2015, 2014 and 2013, respectively.

6. Income Taxes

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

	Years Ended December 31,		
	2015	2014	2013
Current:			
Federal	$ (265)	$ (25)	$ 429
State	—	—	—
Total current provision for income taxes	$ (265)	$ (25)	$ 429
Deferred:			
Federal	$(91,716)	$32,754	$41,175
State	(1,424)	963	903
Total deferred provision for income taxes	$(93,140)	$33,717	$42,078

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,		
	2015	2014	2013
Statutory tax at 35%	$(93,628)	$31,452	$40,167
State taxes, net of federal impact	(1,463)	989	709
Share-based compensation tax shortfall	1,939	1,670	—
Permanent differences	26	37	34
Other differences	(1,035)	(456)	1,597
Valuation allowance	756	—	—
Total	$(93,405)	$33,692	$42,507

In 2015 and 2014, the Company recorded a tax shortfall related to share-based compensation of $1.9 million and $1.7 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. Although we had excess tax benefits related to share-based compensation in prior years, this benefit was not recorded as the excess tax benefits were not realized due to our net operating loss carryforwards.

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 $31.8 million and $110.7 million at December 31, 2015 and 2014, respectively. At December 31, 2014, $14.2 million of deferred taxes expected to be realized within one year were included in current liabilities.

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, 2015	2014
Deferred tax assets:		
Net operating loss carryforwards	$ 88,230	$ 46,730
Other	1,672	1,305
Total deferred tax assets	89,902	48,035
Deferred tax liabilities:		
Difference in depreciation, depletion and capitalization methods — oil and gas properties	(118,534)	(158,647)
Unrealized gain on commodity derivatives	(2,391)	(14,307)
Total deferred tax liabilities	(120,925)	(172,954)
Valuation allowance	(756)	—
Net deferred tax liability	$ (31,779)	$(124,919)

Net operating loss carryforwards for tax purposes have the following expiration dates (in thousands):

Expiration Dates	Amounts	Stock Adjustments	Total
2030	$ 4,083	$ 750	$ 4,833
2031	18,642	1,012	19,654
2032	51,931	2,724	54,655
2033	616	503	1,119
2034	56,511	—	56,511
2035	120,298	—	120,298
Total	$252,081	$ 4,989	$257,070

As of December 31, 2015, we had net operating loss carryforwards of approximately $257.1 million, of which approximately $5 million was generated from the benefit of stock options. When these benefits are realized, they will be credited to additional paid-in capital.

7. Derivative Instruments and Fair Value Measurements

At December 31, 2015, we had the following commodity derivatives positions outstanding:

Commodity and Period	Contract Type	Volume Transacted	Contract Price
Crude Oil			
January 2016 — December 2016	Swap	500 Bbls/d	$62.50/Bbl
January 2016 — December 2016	Swap	250 Bbls/d	$62.55/Bbl
January 2016 — June 2016	Swap	500 Bbls/d	$40.25/Bbl
January 2016 — June 2016	Swap	1,000 Bbls/d	$40.00/Bbl
Natural Gas			
March 2016 — December 2016	Swap	100,000 MMBtu/month	$2.91/MMBtu
March 2016 — December 2016	Swap	100,000 MMBtu/month	$2.95/MMBtu

Approach Resources Inc. and Subsidiaries

Notes to Consolidated Financial Statements — (Continued)

After December 31, 2015, we entered into natural gas swaps covering 400,000 MMBtu per month at an average price of $2.45/MMBtu for February 2016 through March 2017, and natural gas collars covering 200,000 MMBtu per month with a floor price of $2.30/MMBtu and a ceiling price of $2.60/MMBtu for April 2017 through December 2017.

The following summarizes the fair value of our open commodity derivatives as of December 31, 2015 and 2014 (in thousands):

	Balance Sheet Location	Fair Value	
		December 31, 2015	December 31, 2014
Derivatives not designated as hedging instruments			
Commodity derivatives	Unrealized gain on commodity derivatives	$ 6,737	$ 39,951

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

	Income Statement Location	Year Ended December 31,		
		2015	2014	2013
Derivatives not designated as hedging instruments				
Commodity derivatives	Unrealized (loss) gain on commodity derivatives	$(33,214)	$42,113	$(4,596)
	Realized gain (loss) on commodity derivatives	52,489	2,359	(1,048)
		$ 19,275	$44,472	$(5,644)

Unrealized gains and losses, 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. Realized gains and losses are also included in income (expense) on our consolidated statements of operations.

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 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, 2015, 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, 2015, 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 used in estimating our recognized impairment loss represents a nonrecurring Level 3 measurement.

Nonrecurring Fair Value Measurements

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. 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 rate.

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 is the estimated fair value. Our estimates of future cash flows attributable to our oil and gas properties could decline further with commodity prices which may result in additional impairment losses.

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, 2015	
	Carrying Amount	Fair Value
Senior Notes, net	$225,839	$ 82,915

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Notes to Consolidated Financial Statements — (Continued)

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, 2015, 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, 2015. This estimate assumes the maximum potential bonus for 2016 is earned by each executive officer during 2016.

We lease our office space in Fort Worth, Texas, under a non-cancelable agreement that expires on March 31, 2020. We also have non-cancelable operating lease commitments related to office equipment that expire by 2019. The following is a schedule by years of future minimum rental payments required under our operating lease arrangements as of December 31, 2015 (in thousands):

2016	$ 957
2017	967
2018	975
2019	976
2020	246
Total	$4,121

Rent expense under our lease arrangements amounted to $1,002,000, $717,000 and $734,000 for the years ended December 31, 2015, 2014 and 2013, 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.

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.

Approach Resources Inc. and Subsidiaries

Notes to Consolidated Financial Statements — (Continued)

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,		
	2015	2014	2013
Property acquisition costs:			
Unproved properties	$ 653	$ 4,578	$ 5,857
Proved properties	—	—	1,000
Exploration costs	4,439	3,831	2,238
Development costs (1)	146,237	382,995	287,898
Total costs incurred	$151,329	$391,404	$296,993

(1) For the years ended December 31, 2015, 2014 and 2013, development costs include $151,000, $898,000 and $584,000, 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,		
	2015	2014	2013
Revenues	$ 131,336	$ 258,529	$181,302
Production costs	(40,057)	(48,635)	(31,992)
Exploration expense	(4,439)	(3,831)	(2,238)
Depletion	(109,319)	(106,802)	(76,956)
Impairment of oil and gas properties	(220,197)	—	—
Income tax benefit (expense)	86,120	(35,387)	(24,996)
Results of operations	$(156,556)	$ 63,874	$ 45,120

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, 2015, 2014 and 2013, 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 2015, 2014 and 2013. Commodity prices used for the reserve estimates, adjusted for basis differentials, grade and quality, are as follows:

	2015	2014	2013
Oil (per Bbl)	$50.16	$94.56	$97.28
Natural gas liquids (per Bbl)	$15.13	$31.50	$30.16
Gas (per Mcf)	$ 2.64	$ 4.55	$ 3.66

Approach Resources Inc. and Subsidiaries

Notes to Consolidated Financial Statements — (Continued)

Oil, NGL 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 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, 2015, 2014 and 2013, as well as proved developed and proved undeveloped reserves at the beginning and end of each respective year.

Total Proved Reserves	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total (MBoe)
Balance — December 31, 2012	37,252	29,100	174,760	95,479
Extensions and discoveries	14,252	6,531	38,993	27,282
Purchases of minerals in place	62	14	197	109
Production(1)	(1,444)	(951)	(6,737)	(3,517)
Revisions to previous estimates	(4,055)	(2,102)	8,789	(4,692)
Balance — December 31, 2013	46,067	32,593	216,002	114,661
Extensions and discoveries	19,347	10,658	79,454	43,247
Production(1)	(2,024)	(1,461)	(10,773)	(5,281)
Revisions to previous estimates	(8,052)	(883)	15,337	(6,379)
Balance — December 31, 2014	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

(1) Production includes 560 MMcf, 1,390 MMcf and 1,530 MMcf related to field fuel in 2013, 2014 and 2015, respectively.

Approach Resources Inc. and Subsidiaries

Notes to Consolidated Financial Statements — (Continued)

Total Proved Reserves	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total (MBoe)
Proved Developed Reserves:				
January 1, 2013	8,816	11,761	73,178	32,774
December 31, 2013	13,646	14,919	99,742	45,189
January 1, 2014	13,646	14,919	99,742	45,189
December 31, 2014	17,978	19,082	138,961	60,220
January 1, 2015	17,978	19,082	138,961	60,220
December 31, 2015	15,667	20,414	154,652	61,856
Proved Undeveloped Reserves:				
January 1, 2013	28,436	17,339	101,582	62,705
December 31, 2013	32,421	17,674	116,260	69,472
January 1, 2014	32,421	17,674	116,260	69,472
December 31, 2014	37,360	21,825	161,059	86,028
January 1, 2015	37,360	21,825	161,059	86,028
December 31, 2015	38,829	29,072	221,335	104,790

The following is a discussion of the material changes in our proved reserve quantities for the years ended December 31, 2015, 2014 and 2013:

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 recorded net downward revisions totaling 8.7 MMBoe, including the reclassification of 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 also included 13 MMBoe of positive revisions resulting from cost reductions, updated well performance and technical parameters, offset by 9.8 MMBoe of negative revisions 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.

Year Ended December 31, 2014

Extensions and discoveries for 2014 were 43.2 MMBoe, primarily attributable to our development project in the Wolfcamp shale oil resource play in the Permian Basin. During 2014, we recorded downward revisions totaling 6.4 MMBoe, including the reclassification of 9.3 MMBoe of proved undeveloped reserves to probable undeveloped. The reserves reclassified from proved undeveloped to probable undeveloped included 5.8 MMBoe attributable to vertical Canyon locations in Project Pangea that we do not plan to drill within five years from their initial booking, and 3.5 MMBoe attributable to horizontal Wolfcamp locations that are no longer included in our proved development plan. Revisions also included 6.3 MMBoe of positive net revisions attributable to updated well performance and 0.7 MMBoe of positive revisions due to pricing, offset by 4.1 MMBoe of negative revisions resulting from updated technical parameters and costs. We produced 5.3 MMBoe during 2014. This production included 1,390 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.

Approach Resources Inc. and Subsidiaries

Notes to Consolidated Financial Statements — (Continued)

Year Ended December 31, 2013

Extensions and discoveries for 2013 were 27.3 MMBoe, primarily attributable to our development project in the Wolfcamp shale oil resource play in the Permian Basin. We produced 3.5 MMBoe during 2013. This production included 560 MMcf of gas that was produced and used as field fuel (primarily for compressors and artificial lifts) before the gas was delivered to a sales point. During 2013, we recorded downward revisions totaling 4.7 MMBoe. Revisions included the reclassification of 7.8 MMBoe of proved undeveloped reserves to probable undeveloped, partially offset by 3.1 MMBoe of positive revisions attributable to gas that will be produced and utilized as field fuel. The reserves reclassified from proved undeveloped to probable undeveloped were attributable to vertical Canyon locations in Project Pangea. Due to our horizontal Wolfcamp development project, including pad drilling, postponement of these deeper locations beyond five years from initial booking was necessary to integrate their development with the shallower Clearfork and Wolfcamp target zones.

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.

The following table provides the standardized measure of discounted future net cash flows at December 31, 2015, 2014 and 2013 (in thousands):

	Years Ended December 31,		
	2015	2014	2013
Future cash flows	$ 4,097,568	$ 7,430,368	$ 5,953,060
Future production costs	(1,237,888)	(1,704,333)	(1,372,005)
Future development costs	(934,814)	(1,247,446)	(1,154,685)
Future income tax expense	(307,374)	(1,267,025)	(919,454)
Future net cash flows	1,617,492	3,211,564	2,506,916
10% annual discount for estimated timing of cash flows	(1,157,097)	(2,155,749)	(1,830,639)
Standardized measure of discounted future net cash flows	$ 460,395	$ 1,055,815	$ 676,277

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

Approach Resources Inc. and Subsidiaries

Notes to Consolidated Financial Statements — (Continued)

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, 2015	2014	2013
Balance, beginning of period	$ 1,055,815	$ 676,277	$ 494,220
Net change in sales and transfer prices and in production (lifting) costs related to future production	(1,405,864)	(59,920)	74,088
Changes in estimated future development costs	231,900	(388,772)	(301,132)
Sales and transfers of oil and gas produced during the period	(91,278)	(209,893)	(149,310)
Net change due to extensions, discoveries and improved recovery	156,783	534,231	360,080
Net change due to purchase of minerals in place	—	—	1,435
Net change due to revisions in quantity estimates	(59,305)	(78,801)	(61,931)
Previously estimated development costs incurred during the period	146,237	382,995	287,898
Accretion of discount	105,582	113,188	87,937
Other	6,915	(11,897)	1,896
Net change in income taxes	313,610	98,407	(118,904)
Standardized Measure of discounted future net cash flows	$ 460,395	$1,055,815	$ 676,277

11. Supplementary Data

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

	2015 Quarters Ended December 31	September 30	June 30	March 31
Net revenue	$ 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	—	—
Realized gain on commodity derivatives	14,552	12,755	9,281	15,901
Unrealized (loss) gain on commodity derivatives	(10,285)	296	(13,904)	(9,321)
Other income (expense)	225	(91)	12	26
(Loss) income 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)

Approach Resources Inc. and Subsidiaries

Notes to Consolidated Financial Statements — (Continued)

	2014 Quarters Ended			
	December 31	September 30	June 30	March 31
Net revenue	$ 55,070	$ 68,124	$ 73,408	$ 61,927
Net operating expenses	(50,136)	(45,525)	(50,812)	(44,899)
Interest expense, net	(5,715)	(5,442)	(5,357)	(5,137)
Equity in earnings (losses) of investee	5	—	(186)	—
Realized gain (loss) on commodity derivatives	7,782	(764)	(3,320)	(1,339)
Unrealized gain (loss) on commodity derivatives	36,907	18,810	(7,678)	(5,926)
Other income (expense)	176	—	(109)	—
Income before income tax	44,089	35,203	5,946	4,626
Income tax provision	17,102	12,756	2,153	1,681
Net income	$ 26,987	$ 22,447	$ 3,793	$ 2,945
Basic net income applicable to common stockholders per common share	$ 0.68	$ 0.57	$ 0.10	$ 0.08
Diluted net income applicable to common stockholders per common share	$ 0.68	$ 0.57	$ 0.10	$ 0.08

	2013 Quarters Ended			
	December 31	September 30	June 30	March 31
Net revenue	$ 58,565	$ 44,196	$ 42,272	$ 36,269
Net operating expenses	(40,402)	(34,314)	(31,329)	(31,665)
Interest expense, net	(5,225)	(5,179)	(2,451)	(1,229)
Equity in (losses) earnings of investee	(4)	340	(64)	(116)
Gain on sale of Wildcat pipeline	90,743	—	—	—
Realized gain (loss) on commodity derivatives	199	(840)	(714)	307
Unrealized (loss) gain on commodity derivatives	(1,348)	(3,438)	4,290	(4,100)
Income (loss) before income tax (benefit)	102,528	765	12,004	(534)
Income tax provision (benefit)	38,207	270	4,217	(187)
Net income (loss)	$ 64,321	$ 495	$ 7,787	$ (347)
Basic net income (loss) applicable to common stockholders per common share	$ 1.65	$ 0.01	$ 0.20	$ (0.01)
Diluted net income (loss) applicable to common stockholders per common share	$ 1.65	$ 0.01	$ 0.20	$ (0.01)

Approach Resources Inc.
Index to Exhibits

Exhibit Number	Description of Exhibit
3.1	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).
3.2	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	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).
4.3	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).
4.4	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).
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†	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).
10.4†	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).
10.5†	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).
10.6	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).
10.7†	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).

Approach Resources Inc.
Index to Exhibits — (Continued)

Exhibit Number	Description of Exhibit
10.8†	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).
10.9†	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).
10.10†	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).
10.11†	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).
10.12†	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).
10.13†	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).
10.14	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).
10.15	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).
10.16	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).
10.17	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).
10.18	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).
10.19	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).

Approach Resources Inc.
Index to Exhibits — (Continued)

Exhibit Number	Description of Exhibit
10.20	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 10.1 to the Company's Current Report on Form 8-K filed May 8, 2014, and incorporated herein by reference).
10.21	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).
10.22	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 for the three months ended September 30, 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 Hein & Associates LLP.
*23.2	Consent of DeGolyer and MacNaughton.
*31.1	Certification by the President and 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 President and 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.

EXHIBIT 12.1

APPROACH RESOURCES INC.

STATEMENT OF COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

(in thousands, except ratios)	Years ended December 31, 2011	2012	2013	2014	2015
COMPUTATION OF EARNINGS (LOSS):					
Earnings (loss) before income taxes	$10,730	$ 9,722	$114,763	$ 89,864	$(267,509)
Fixed charges	3,426	4,766	14,153	21,670	25,089
	$14,156	$14,488	$128,916	$111,534	$(242,420)
COMPUTATION OF FIXED CHARGES:					
Interest expense(1)	$ 3,402	$ 4,737	$ 14,125	$ 21,656	$ 25,066
Implicit interest in rent	24	29	28	14	23
	$ 3,426	$ 4,766	$ 14,153	$ 21,670	$ 25,089
Ratio of earnings (loss) to fixed charges (2)	4.13x	3.04x	9.11x	5.15x	— (3)

(1) For purposes of computing this ratio, we have excluded interest income from interest expense amounts reported on the consolidated statement of operations.

(2) The ratio has been computed by dividing earnings by fixed charges. For purposes of computing the ratio, the numerator consists of the sum of (i) earnings, which includes income before income taxes, and (ii) fixed charges. The denominator consists of fixed charges, which includes interest expense and a portion of rentals representative of an implicit interest factor for such rentals.

(3) Due to our net loss for the year ended December 31, 2015, the coverage ratio for this period was less than 1:1. To achieve a coverage ratio of 1:1, we would have needed additional earnings of approximately $242.4 million for the year ended December 31, 2015.

Exhibit 21.1

Subsidiaries of Approach Resources Inc.

Name	Jurisdiction of Incorporation or Formation
Approach Oil & Gas Inc.	Delaware
Approach Operating, LLC	Delaware
Approach Delaware, LLC	Delaware
Approach Resources I, LP	Texas
Approach Services, LLC	Delaware
Approach Midstream Holdings, LLC	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement (No. 333-195880) on Form S-3, Registration Statements (No. 333-208003, 333-183069 and 333-148951) on Form S-8 of Approach Resources Inc. of our reports dated March 4, 2016, relating to our audits of the consolidated financial statements and internal control over financial reporting, which appear in this Annual Report on Form 10-K of Approach Resources Inc. for the year ended December 31, 2015.

*/s/ **HEIN** & ASSOCIATES LLP*
Dallas, Texas
March 4, 2016

Exhibit 23.2

DEGOLYER AND MACNAUGHTON
5001 SPRING VALLEY ROAD
SUITE 800 EAST
DALLAS, TEXAS 75244

March 4, 2016

Approach Resources Inc.
One Ridgmar Centre
6500 West Freeway, Suite 800
Fort Worth, Texas 76116

Ladies and Gentlemen:

We hereby consent to the use of the name DeGolyer and MacNaughton, to references to DeGolyer and MacNaughton as an independent petroleum engineering consulting firm, to the inclusion of references to our third party letter report dated February 10, 2014, containing our opinion on the proved reserves attributable to certain properties owned by Approach Resources Inc. as of December 31, 2013, our third party letter report dated January 29, 2015, containing our opinion on the proved reserves attributable to certain properties owned by Approach Resources Inc. as of December 31, 2014, and to our third party letter report dated January 27, 2016, containing our opinion on the proved reserves attributable to certain properties owned by Approach Resources Inc. as of December 31, 2015, under the headings "Part I – Item 2. Properties," "Part II — Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations," and "Notes to Consolidated Financial Statements — 10. Disclosures About Oil and Gas Producing Activities (unaudited)" in Approach Resources Inc.'s Annual Report on Form 10-K for the year ended December 31, 2015 (the Annual Report). We further consent to the inclusion of our third party letter report dated January 27, 2016, containing our opinion on the proved reserves attributable to certain properties owned by Approach Resources Inc. as of December 31, 2015, as an exhibit in the Annual Report.

We hereby further consent to the incorporation by reference of our name and such aforementioned information with respect to the oil and gas reserves of Approach Resources Inc. in Registration Statement (No. 333-195880) on Form S-3 and Registration Statements (No. 333-208003, 333-183069 and 333-148951) on Form S-8 of Approach Resources Inc.

Very truly yours,

/s/ DeGOLYER and MacNAUGHTON

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

Exhibit 31.1

Certification

I, J. Ross Craft, certify that:

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

Date: March 4, 2016

/s/ J. Ross Craft
J. Ross Craft
Chairman of the Board, Chief Executive Officer and President
(Principal Executive Officer)

Exhibit 31.2

Certification

I, Sergei Krylov, certify that:

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

Date: March 4, 2016

/s/ Sergei Krylov
Sergei Krylov
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 32.1

Certification of President and Chief Executive Officer of Approach Resources Inc.
(Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002)

In connection with the annual report of Approach Resources Inc. (the “Company”) on Form 10-K for the period ended December 31, 2015, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, J. Ross Craft, President and Chief Executive Officer of the Company, hereby certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

APPROACH RESOURCES INC.

Date: March 4, 2016

/s/ J. Ross Craft
J. Ross Craft
Chairman of the Board, Chief Executive Officer and President
(Principal Executive Officer)

Exhibit 32.2

Certification of Chief Financial Officer of Approach Resources Inc.
(Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002)

In connection with the annual report of Approach Resources Inc. (the "Company") on Form 10-K for the period ended December 31, 2015, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Sergei Krylov, Chief Financial Officer of the Company, hereby certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

APPROACH RESOURCES INC.

Date: March 4, 2016

/s/ Sergei Krylov
Sergei Krylov
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 99.1

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

January 27, 2016

Approach Resources Inc.
6500 West Freeway, Suite 800
Fort Worth, Texas 76116

Ladies and Gentlemen:

Pursuant to your request, we have prepared estimates of the extent and value of the net proved oil, condensate, natural gas liquids (NGL), and gas reserves, as of December 31, 2015, of certain properties that Approach Resources Inc. (Approach) has represented that it owns. These properties are located in the State of Texas. This evaluation was completed on January 29, 2016. Approach has represented that these properties account for 100 percent on a net equivalent barrel basis of Approach's net proved reserves as of December 31, 2015. The net proved reserves estimates prepared by us have been prepared in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the Securities and Exchange Commission (SEC) of the United States. This report was prepared in accordance with guidelines specified in Item 1202 (a)(8) of Regulation S-K and is to be used for inclusion in certain SEC filings by Approach.

Reserves estimates included herein are expressed as net reserves. Gross reserves are defined as the total estimated petroleum to be produced from these properties after December 31, 2015. Net reserves are defined as that portion of the gross reserves attributable to the interests owned by Approach after deducting all interests owned by others.

Gas quantities estimated herein are expressed as fuel gas and sales gas. Fuel gas is that portion of the produced gas to be used in field operations. Sales gas is defined as that portion of the total gas to be delivered into a gas pipeline for sale after separation, processing, fuel use, and flare. Gas reserves are expressed at a temperature base of 60 degrees Fahrenheit (°F) and at a pressure base of 14.65 pounds per square inch absolute (psia). Condensate reserves estimated herein are those to be recovered by conventional lease separation. NGL reserves are those attributed to the leasehold interests according to processing agreements.

Values of proved reserves shown herein are expressed in terms of future gross revenue, future net revenue, and present worth. Future gross revenue is that revenue which will accrue to the evaluated interests from the production and sale of the estimated net reserves. Future net revenue is calculated by deducting estimated production taxes, ad valorem taxes, operating expenses, and capital and abandonment costs from the future gross revenue. Operating expenses include field operating expenses, transportation expenses, compression charges, and an allocation of overhead that directly relates to production activities. Future income tax expenses were not taken into account in the preparation of these estimates. Present worth is defined as future net revenue discounted at a specified arbitrary discount rate compounded annually over the expected period of realization. Present worth should not be construed as fair market value because no consideration was given to additional factors that influence the prices at which properties are bought and sold.

Estimates of oil, condensate, NGL, and gas reserves and future net revenue should be regarded only as estimates that may change as further production history and additional information become available. Not only are such reserves and revenue estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Data used in this evaluation were obtained from reviews with Approach personnel, from Approach files, from records on file with the appropriate regulatory agencies, and from public sources. Additionally, this information includes data supplied by IHS Global Inc.; Copyright 2015 IHS Global Inc. In the preparation of this report we have relied, without independent verification, upon such information furnished by Approach with respect to property interests, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination of the properties was not considered necessary for the purposes of this report.

Methodology and Procedures

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007)." 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.

Based on the current stage of field development, production performance, the development plans provided by Approach, and the analyses of areas offsetting existing wells with test or production data, reserves were categorized as proved.

For the fields evaluated in this report, structure and isopach maps were prepared by Approach 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 by Approach to the isopach maps to obtain estimates of original oil in place (OOIP) or original gas in place (OGIP). These maps were reviewed in detail and found acceptable to use for the purpose of this report.

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 of similar completion for which more data were available.

In certain cases, when the previously named methods could not be used, reserves were estimated by analogy with similar wells or reservoirs for which more complete data were available.

Definition of Reserves

Petroleum reserves estimated by us included in this report are classified as proved. Only proved reserves have been evaluated for this report. Reserves classifications used by us in this report are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

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

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

(A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

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

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

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

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

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

Developed oil and gas reserves – Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

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

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

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

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

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

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in [section 210.4–10 (a) Definitions], or by other evidence using reliable technology establishing reasonable certainty.

Primary Economic Assumptions

The following economic assumptions were used for estimating existing and future prices and costs:

Oil and Condensate Prices

Approach has represented that the oil and condensate prices were based on a reference price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. Approach supplied differentials by field to a West Texas Intermediate reference price of $50.16 per barrel and the prices were held constant thereafter. The volume-weighted average oil and condensate price attributable to estimated proved reserves was $47.09 per barrel.

NGL Prices

Approach has represented that the NGL prices were based on a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. The volume-weighted average NGL price attributable to estimated proved reserves was $15.13 per barrel.

Gas Prices

Approach has represented that the gas prices were based on a reference price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. The gas prices were calculated for each property using differentials and Btu values provided by Approach to the Henry Hub reference price of $2.64 per million British thermal units and held constant thereafter. The volume-weighted average price attributable to estimated proved reserves was $2.347 per thousand cubic feet of gas.

Operating Expenses, Capital Costs, and Abandonment Costs

Operating expenses and capital costs, based on information provided by Approach, were used in estimating future costs required to operate the properties. In certain cases, future costs, either higher or lower than existing costs, may have been used because of anticipated changes in operating conditions. These costs were not escalated for inflation. Abandonment costs were provided by Approach.

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its oil and gas reserves, we are not aware of any such governmental actions which would restrict the recovery of the December 31, 2015, estimated oil and gas reserves.

Our estimates of Approach's net proved reserves attributable to the evaluated properties are based on the definitions of proved reserves of the SEC and are as follows, expressed in thousands of barrels (Mbbl), millions of cubic feet (MMcf), and thousands of barrels of oil equivalent (Mboe):

	Estimated by DeGolyer and MacNaughton Net Proved Reserves as of December 31, 2015				
	Oil and Condensate (Mbbl)	NGL (Mbbl)	Fuel Gas (MMcf)	Sales Gas (MMcf)	Oil Equivalent (Mboe)
Permian Basin					
Proved Developed	15,667	20,414	16,933	137,262	61,780
Proved Undeveloped	38,829	29,072	25,669	195,666	104,790
Total Permian Basin	**54,496**	**49,486**	**42,602**	**332,929**	**166,570**
East Texas Basin					
Proved Developed	0	0	15	442	76
Proved Undeveloped	0	0	0	0	0
Total East Texas Basin	**0**	**0**	**15**	**442**	**76**
Total Proved	**54,496**	**49,486**	**42,617**	**333,371**	**166,646**

Note: Gas is converted to oil equivalent using an energy equivalent factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent.

The estimated future revenue attributable to Approach's interests in the proved reserves, as of December 31, 2015, of the properties evaluated is summarized as follows, expressed in thousands of dollars (M$):

	Proved			
	Developed Producing	Developed Nonproducing	Undeveloped	Total
Future Gross Revenue, M$	1,352,359	10,722	2,734,487	4,097,568
Production and Ad Valorem Taxes, M$	100,139	703	192,580	293,422
Operating Expenses, M$	410,859	1,880	531,727	944,466
Capital and Abandonment Costs, M$	16,451	2,920	915,443	934,814
Future Net Revenue, M$	824,910	5,220	1,094,737	1,924,867
Present Worth at 10 Percent, M$	390,804	1,123	112,057	503,984

Note: Future income tax expenses were not taken into account in the preparation of these estimates.

In our opinion, the information relating to estimated proved reserves, estimated future net revenue from proved reserves, and present worth of estimated future net revenue from proved reserves of oil, condensate, natural gas liquids, and gas contained in this report has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7, 932-235-50-9, 932-235-50-30, and 932-235-50-31(a), (b), and (e) of the Accounting Standards Update 932-235-50, *Extractive Industries – Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures* (January 2010) of the Financial Accounting Standards Board and Rules 4–10(a) (1)–(32) of Regulation S–X and Rules 302(b), 1201, 1202(a) (1), (2), (3), (4), (8), and 1203(a) of Regulation S–K of the Securities and Exchange Commission; provided, however, that (i) future income tax expenses have not been taken into account in estimating the future net revenue and present worth values set forth herein and (ii) estimates of the proved developed and proved undeveloped reserves are not presented at the beginning of the year.

To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature, we, as engineers, are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

DeGolyer and MacNaughton

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. DeGolyer and MacNaughton does not have any financial interest, including stock ownership, in Approach. Our fees were not contingent on the results of our evaluation. This letter report has been prepared at the request of Approach. DeGolyer and MacNaughton has used all assumptions, data, procedures, and methods that it considers necessary and appropriate to prepare this report.

Submitted,

/s/ DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

/s/ Paul J. Szatkowski

Paul J. Szatkowski, P.E.
Senior Vice President
DeGolyer and MacNaughton

[SEAL]

CERTIFICATE of QUALIFICATION

I, Paul J. Szatkowski, Petroleum Engineer with DeGolyer and MacNaughton, 5001 Spring Valley Road, Suite 800 East, Dallas, Texas, 75244 U.S.A., hereby certify:

1. That I am a Senior Vice President with DeGolyer and MacNaughton, which company did prepare the letter report addressed to Approach dated January 27, 2016, and that I, as Senior Vice President, was responsible for the preparation of this letter report.
2. That I attended Texas A&M University, and that I graduated with a Bachelor of Science degree in Petroleum Engineering in 1974; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the International Society of Petroleum Engineers and the American Association of Petroleum Geologists; and that I have in excess of 40 years of experience in oil and gas reservoir studies and reserves evaluations.

/s/ Paul J. Szatkowski

Paul J. Szatkowski, P.E.
Senior Vice President
DeGolyer and MacNaughton

[SEAL]