



PetroQuest Energy, Inc.

**DRILLING DOWN  
ON THE COTTON VALLEY**

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**2016 ANNUAL REPORT**



## ABOUT THE COVER

The Cotton Valley sands extend from East Texas to Florida, do not reach the surface, originate from many high energy depocenters, and include stacked barrier-island, strandplain, and fluvial-deltaic sandstones. The East Texas Cotton Valley sandstone group is typically greater than 1000 ft thick, and has a range in porosity generally around +/- 10%, and permeability ranging from 0.05mD to 1-3mD. Cotton Valley sands source their hydrocarbon content through migration from the underlying Bossier/Haynesville Shales. These sands often require moderate hydraulic fracturing to produce appreciable quantities of gas and condensate.

By contrast, most shale plays were typically deposited as mud in low-energy, quiet water depositional environments. Deposition of organic-rich matter occurred concurrently with the fine-grained sediment deposition, setting up shale plays as self-sourcing systems where gas is created and stored within. Subsequent burial and compression of these sediments produce a rock that has limited horizontal permeability and extremely limited vertical permeability, with permeabilities ranging from 0.01mD to 0.00001mD. Porosity ranges fall between 2% at the low end, and 14% at the high end. Due to the extremely low permeabilities in shale plays, significant hydraulic fracturing is necessary to produce hydrocarbons.

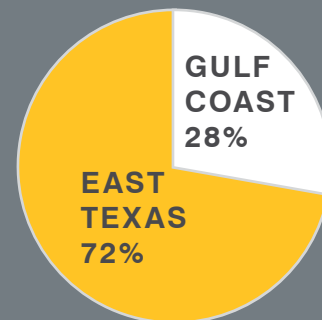
## ABOUT PETROQUEST

Founded in 1985, PetroQuest Energy is a U.S.-focused exploration and development company of crude oil and natural gas in Louisiana and Texas. Commodity prices change but our strategy is strong and flexible enough to withstand a down cycle and persevere. Our industry is a business of long-term resourcefulness balanced with near-term inventiveness. Since our founding, we've focused on building an energy company with the diversity to preserve returns through any cycle. We believe PetroQuest will persevere through the current commodity environment, add incrementally to its reserve and production base, improve well performance, and be well prepared for the future.

## CORE ASSETS



## 2016 RESERVES



115 BCFE



### 2016: A PIVOTAL YEAR OF PREPARATION FOR A RETURN TO GROWTH



**Charles T. Goodson**  
Chairman, President & CEO

Ours is a cyclical business, and if anyone needed a reminder, the global oil and gas industry downturn of the past two years proved the point. From our beginnings as a private prospect generation company in 1986, to our formation as a public company in 1998, and more recently to the posture we assumed in 2016, PetroQuest's history parallels the cycles of the energy business over the past 31 years. That we have endured many cycles and market volatility in our history is primarily a tribute to the ingenuity and commitment of our employees. Largely due to the efforts of our team, I have the privilege to report that PetroQuest has emerged from this latest down cycle with an attractive asset portfolio, a strengthened balance sheet and a culture of creating value at all points of the energy business cycle.

Having founded the company and led the men and women who have helped navigate the Company through multiple cycles, I can write with confidence about our past, present and future ability to successfully manage through the uncertainties inherent to the oil and natural gas markets. It is my sincere belief that our people, strategy and asset quality inspired the confidence in our Company that shareholders and bondholders needed to help us achieve some critical milestones in 2016 together.

As I write this letter, there have been over 114 upstream oil and gas companies who have declared Chapter 11 bankruptcy between 2014 and 2016, wiping out billions of dollars in value for equity and debt investors. Although we appreciate that many competitors perceived no other alternative and they were tempted to "clear the decks" during difficult market conditions, we chose to lead and to find a new path forward that preserves value.

Ours is a cyclical business, and if anyone needed a reminder, the global oil and gas industry downturn of the past two years proved the point. From our beginnings as a private prospect generation company in 1986, to our formation as a

PetroQuest chose to make the critical decisions necessary to adapt our company to the new realities of the oil and gas market, preserve value and live to grow another day. That day is upon us.

I believe the strategic decision to aggressively extend our debt maturities rather than capitulate distinguishes PetroQuest in the market. Investors can have confidence that we are good stewards of capital and will act to preserve value for both equity and debt holders. In 2016, we worked diligently to preserve the interests of all stakeholders by paying off our bank debt and negotiating with supportive bondholders to refinance our notes. Since the beginning of 2015, we have refinanced or repaid all of our year-end 2014 debt of \$425 million, all achieved during a prolonged period of dysfunctional capital markets. As a result, we have the financial resources needed to fund our 2017 drilling program.

Strategy is, of course, only part of our story, in that we have identified the operational steps necessary to successfully execute our program over the next several years. Toward that end, we completed the divestment program necessary for us to high-grade our core assets and positioned PetroQuest for the next commodity cycle upswing. With a renewed focus on our core assets, we believe we can achieve the consistent growth in production required to continue deleveraging our balance sheet.

**We believe we can achieve the consistent growth in production required to continue deleveraging our balance sheet.**

Today, our asset portfolio is focused on our best performing assets, and we expect planned development drilling in the Cotton Valley and recompletion work at Thunder Bayou will drive our growth in 2017.

The Cotton Valley has been a priority for PetroQuest for several years because assets in this region of East Texas possess several



positive attributes in the current price environment. First, wells in this area have enviable reservoir rock quality that exhibit production profiles arguably more like conventional oil wells than the high-decline resource plays that have been the industry's focus in recent years.

For comparison, our Cotton Valley acreage consists of high permeability sandstone as compared to lower permeability, unconventional shales. Sandstone reservoirs like the Cotton Valley exhibit the repeatability and cost of an unconventional shale, but the rock quality is more akin to a conventional Gulf Coast sandstone.

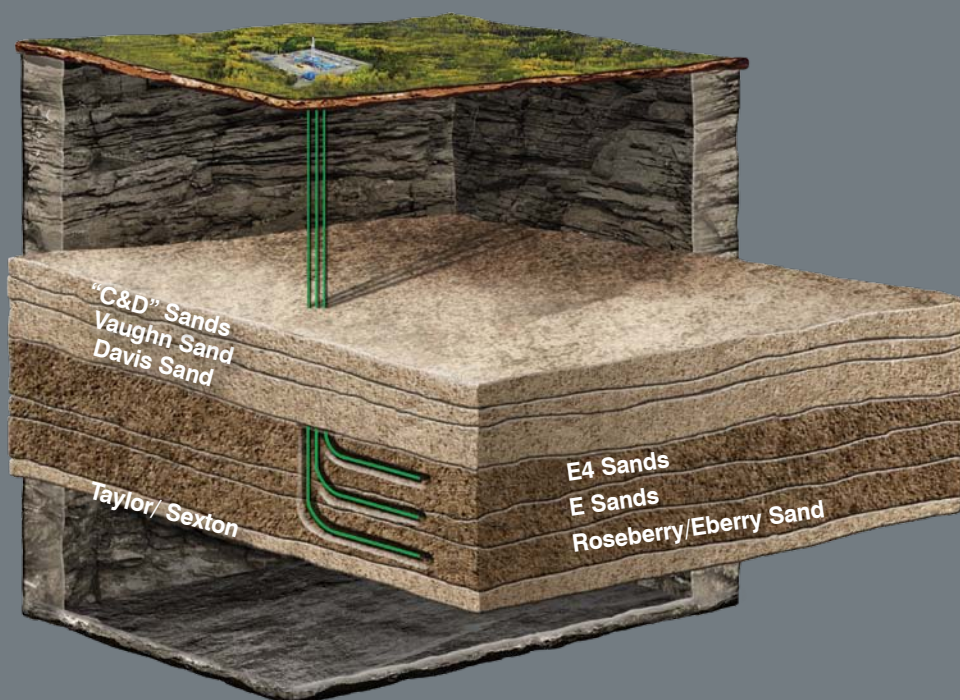
The proof is in the numbers. Our operations team increased average initial production rates for Cotton Valley wells by 105% since 2011, while decreasing our cost to drill per lateral foot by 45% over the same period. Our team is generating higher well productivity using less capital through careful analysis and tailoring well completion designs.

**Our operations team increased average initial production rates for Cotton Valley wells by 105% since 2011, while decreasing our cost to drill per lateral foot by 45% over the same period.**

What makes the Cotton Valley trend even more responsive to analysis and experimentation is the fact that there is a great deal of well control from decades of vertical production history, along with ample cores and mud logs. All of this data is useful in high-grading opportunities and de-risking our Cotton Valley drilling program.

In addition, we believe there are significant opportunities to tap a large, existing resource already in place. Vertical well development in this area identified multiple target benches throughout a 1,400-foot thick sand column, but they were inefficiently drained using the prevailing vertical well technology of the time. This is an ideal geologic setting to apply the modern development techniques of horizontal development drilling and new completion techniques.

## COTTON VALLEY BENCHES





Furthermore, Cotton Valley economics are resilient. At a \$2.50 per Mcf price deck held flat, 91% of well cost payout can be achieved in the first year based on current drilling costs. Quite simply, our Cotton Valley asset is a stable, consistent, shallow decline area offering myriad visible growth opportunities.

Our Company's 2017 drilling program was designed to assess certain operational concepts not previously evaluated, including drilling longer laterals, testing tighter spacing, obtaining micro-seismic data and implementing pad drilling. We believe the information obtained through these operational concept tests will help fine tune our future well design and location selection process. It's worth highlighting that we have only drilled and completed 22 horizontal wells on this 50,000-acre position. Based on the rate of improvement that we saw between our PQ#1 and the most recent group of wells gives us confidence that armed with this new data we will be able to continue to achieve improvements to extract these resources in place.

Our Thunder Bayou/La Cantera assets are cornerstone assets, generating free cash flow for reinvestment into the Cotton Valley. At the end of 2016, Thunder Bayou was producing 10 MMCFe per day; this well has performed better than our pre-drill projections throughout its production life. As with any well, however, Thunder Bayou's production rates had declined through 2016, so we decided to recompleting this well in the Upper Cris R-2 pay zone, which is a 150-foot thick sand section. After completing the upper pay zone in mid-February the well is producing approximately 39,000 Mcf/d of gas 1,500 Bbls/d of oil and 2,200 Bbls/d of NGLs. Our internally generated and operated Thunder Bayou well is a world class onshore discovery, which has the highest sustained deliverability in the Gulf Coast and we believe in onshore United States. This project along with our 8-10 well Cotton Valley program sets the stage for significant deleveraging through organic production growth in 2017.

As I'm writing this letter, we have approximately 11.0 Bcf of gas hedged for 2017 consisting of 20 million per day in the first quarter, 30 million per day in the second and third quarters and 40 million per day in the fourth quarter. Additionally, we have



Thunder Bayou production at 39,000 Mcf/d of gas, 1,500 Bbls/d of oil and 2,200 Bbls/d of NGLs after recompleting in February 2017.

hedged 2.7 Bcf for the first quarter of 2018. Our hedge program was designed to increase throughout this year to cover our expected growth in underlying gas production while protecting our anticipated cash flows.

On behalf of our Board of Directors and employees, I would once again like to express PetroQuest Energy's appreciation to our creditors for their flexibility and patience while we worked to address the company's debt maturities last year. I believe their constructive approach demonstrates a fundamental confidence in our strategy, our operations, and most importantly, confidence in the ability of our team to execute our growth plan. I am confident that the best days for PetroQuest still lie ahead.

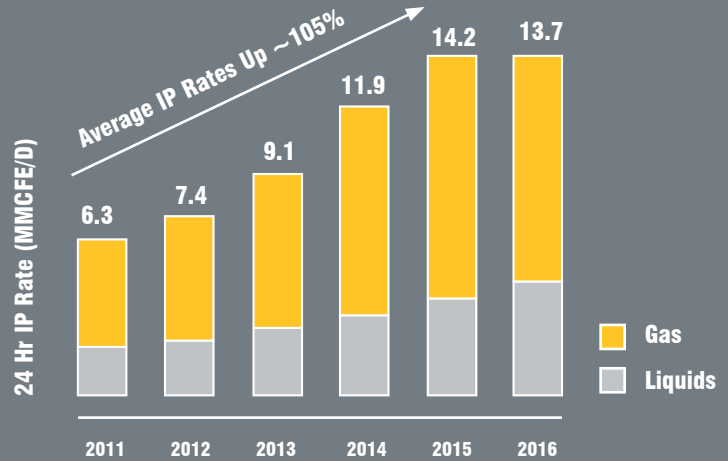
Sincerely,

Charles T. Goodson  
Chairman, President and Chief Executive Officer  
March 16, 2017

## ABOUT THE COTTON VALLEY SAND PLAY

Our Cotton Valley acreage consists of high permeability sandstone as compared to lower permeability, unconventional shales. Sandstone reservoirs like the Cotton Valley exhibit the repeatability and cost of an unconventional shale, but the rock quality is more akin to a conventional Gulf Coast sandstone.

## COTTON VALLEY IP RATES



**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, 2016  
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: 001-32681

**PETROQUEST ENERGY, INC.**  
(Exact name of registrant as specified in its charter)

Delaware 72-1440714  
State of incorporation: I.R.S. Employer Identification No.

400 E. Kaliste Saloom Road, Suite 6000  
Lafayette, Louisiana 70508  
(Address of principal executive offices) (Zip Code)  
Registrant's telephone number, including area code: (337) 232-7028

**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 \$.001 per share	New York Stock Exchange

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

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

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

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes  No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes  No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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. (Check one):

Large accelerated filer Accelerated filer

Non-accelerated filer (Do not check if a smaller reporting company) Smaller reporting company

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

The aggregate market value of the voting common equity held by non-affiliates of the registrant as of June 30, 2016, based on the \$3.33 per share closing price for the registrant's Common Stock, par value \$.001 per share, as quoted on the New York Stock Exchange, was approximately \$52,314,000 (for purposes of this disclosure, the registrant assumed its directors and executive officers were affiliates).

As of March 2, 2017, the registrant had outstanding 21,223,090 shares of Common Stock, par value \$.001 per share.

Document incorporated by reference: portions of the definitive Proxy Statement of PetroQuest Energy, Inc. to be filed pursuant to Regulation 14A under the Securities Exchange Act of 1934 with respect to the Annual Meeting of Stockholders to be held on May 16, 2017, which are incorporated by reference into Part III of this Form 10-K.

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**CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS**

This Annual Report on Form 10-K (this "Form 10-K") contains "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"). All statements other than statements of historical facts included in and incorporated by reference into this Form 10-K are forward looking statements. These forward-looking statements are subject to certain risks, trends and uncertainties that could cause actual results to differ materially from those projected.

Among those risks, trends and uncertainties are:

- the volatility of oil and natural gas prices and significantly depressed oil prices since the end of 2014;
- our indebtedness and the significant amount of cash required to service our indebtedness;
- our ability to obtain adequate financing when the need arises to execute our long-term strategy and to fund our planned capital expenditures;
- limits on our growth and our ability to finance our operations, fund our capital needs and respond to changing conditions imposed by the Multidraw Term Loan Agreement (as defined below) and restrictive debt covenants;
- the effects of a financial downturn or negative credit market conditions on our liquidity, business and financial condition;
- losses or limits on potential gains resulting from hedging production;
- our ability to post additional collateral to satisfy our offshore decommissioning obligations;
- our ability to find, develop, produce and acquire additional oil and natural gas reserves that are economically recoverable;
- approximately 54% of our production being exposed to the additional risk of severe weather, including hurricanes and tropical storms, as well as flooding, coastal erosion and sea level rise;
- Securities and Exchange Commission (sometimes referred to herein as the "SEC") rules that could limit our ability to book proved undeveloped reserves in the future;
- the likelihood that our actual production, revenues and expenditures related to our reserves will differ from our estimates of proved reserves;
- our ability to identify, execute or efficiently integrate future acquisitions;
- the loss of key management or technical personnel;
- losses and liabilities from uninsured or underinsured drilling and operating activities;
- ceiling test write-downs resulting, and that could result in the future, from lower oil and natural gas prices;
- our ability to market our oil and natural gas production;
- changes in laws and governmental regulations, increases in insurance costs or decreases in insurance availability, and delays in our offshore exploration and drilling activities that may result from the April 22, 2010 sinking of the Deepwater Horizon and subsequent oil spill in the Gulf of Mexico;
- regulatory initiatives relating to oil and natural gas development, hydraulic fracturing, and derivatives;
- proposed changes to U.S. tax laws;
- competition from larger oil and natural gas companies;
- the operating hazards attendant to the oil and gas business;

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- governmental regulation relating to environmental compliance costs and environmental liabilities;
- the operation and profitability of non-operated properties;
- potential conflicts of interest resulting from ownership of working interests and overriding royalty interests in certain of our properties by our officers and directors;
- the loss of our information and computer systems;
- the impact of terrorist activities on global economies;
- putative class action lawsuits that may result in substantial expenditures and divert management's attention;
- the volatility of our stock price; and
- our ability to meet the continued listing standards of the New York Stock Exchange with respect to our common stock or to cure any deficiency with respect thereto.

Although we believe that the expectations reflected in these forward-looking statements are reasonable, we cannot assure you that such expectations reflected in these forward looking statements will prove to have been correct.

When used in this Form 10-K, the words “expect,” “anticipate,” “intend,” “plan,” “believe,” “seek,” “estimate” and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain these identifying words. Because these forward-looking statements involve risks and uncertainties, actual results could differ materially from those expressed or implied by these forward-looking statements for a number of important reasons, including those discussed under “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” “Risk Factors” and elsewhere in this Form 10-K.

You should read these statements carefully because they discuss our expectations about our future performance, contain projections of our future operating results or our future financial condition, or state other “forward-looking” information. You should be aware that the occurrence of any of the events described under “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” “Risk Factors” and elsewhere in this Form 10-K could substantially harm our business, results of operations and financial condition and that upon the occurrence of any of these events, the trading price of our common stock could decline, and you could lose all or part of your investment.

We cannot guarantee any future results, levels of activity, performance or achievements. Except as required by law, we undertake no obligation to update any of the forward-looking statements in this Form 10-K after the date of this Form 10-K.

As used in this Form 10-K, the words “we,” “our,” “us,” “PetroQuest” and the “Company” refer to PetroQuest Energy, Inc., its predecessors and subsidiaries, except as otherwise specified. We have provided definitions for some of the oil and natural gas industry terms used in this Form 10-K in “Glossary of Certain Oil and Natural Gas Terms” beginning on page 57.

## Part I

### Item 1 and 2. **Business and Properties Items**

#### **Overview**

PetroQuest Energy, Inc. is an independent oil and gas company incorporated in the State of Delaware with primary operations in Texas, Louisiana and the shallow waters of the Gulf of Mexico. We seek to grow our production, proved reserves, cash flow and earnings at low finding and development costs through a balanced mix of exploration, development and acquisition activities. From the commencement of our operations through 2002, we were focused exclusively in the Gulf Coast Basin with onshore properties principally in southern Louisiana and offshore properties in the shallow waters of the Gulf of Mexico shelf. During 2003, we began the implementation of our strategic goal of diversifying our reserves and production into longer life and lower risk onshore properties with our acquisition of the Carthage Field in East Texas. As part of the strategic shift to diversify our asset portfolio and lower our geographic and geologic risk profile, we refocused our opportunity selection processes to reduce our average working interest in higher risk projects, shift capital to higher probability of success onshore wells and mitigate the risks associated with individual wells by expanding our drilling program across multiple basins. From 2005 through 2015, we

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were actively acquiring acreage and drilling wells primarily in the Woodford Shale play in Oklahoma. We divested all of our acreage and producing wells in Oklahoma in three transactions that closed in June 2015, April 2016 and October 2016 (the "Oklahoma Divestitures"). See Note 2 - Acquisitions and Divestitures.

Our liquidity position has been negatively impacted by the prolonged decline in commodity prices that began in late 2014. In response, we executed the following actions during 2015 and 2016 aimed at preserving liquidity, reducing overall debt levels and extending debt maturities:

- Completed the Oklahoma Divestitures for \$292.6 million;
- Reduced our 2016 capital expenditures by 75% as compared to 2015 capital expenditures of approximately \$65 million;
- Completed two debt exchanges reducing debt maturing in 2017 from \$350 million to \$22.7 million;
- Reduced total debt 32% from \$425 million at December 31, 2014 to \$290.3 million at December 31, 2016;
- Entered into a new \$50 million Multidraw Term Loan Agreement maturing in 2020;
- Suspended the quarterly dividend on our outstanding Series B Preferred Stock saving \$5.1 million annually; and
- Secured a new drilling joint venture in East Texas.

In addition to extending the maturity on approximately \$113.0 million of debt due in 2017 to 2021, our September 2016 debt exchange permits us to reduce our cash interest expense on \$243.5 million of debt from 10% cash to 1% cash and 9% payment-in-kind for the first three semi-annual interest payments, which is expected to provide us with more than \$30 million of cash interest savings during 2017 and 2018. To enhance our liquidity and provide capital to refinance the remaining 10% Senior Notes due 2017 (the "2017 Notes"), in October 2016, we entered into a new \$50 million Multidraw Term Loan Agreement (the "Multidraw Term Loan Agreement") maturing in 2020, that replaced our prior bank credit facility which had no borrowing base on the date of termination. We currently have a more favorable outlook on oil and gas prices for 2017 than prices experienced in 2016. We have recently recompleted our Thunder Bayou well in South Louisiana into a larger sand package and commenced the East Texas joint venture drilling program where we expect to drill eight to ten gross wells during 2017. As a result, we expect to begin growing production during 2017 as compared to 2016.

## Business Strategy

*Preserve Our Liquidity and Strengthen Our Balance Sheet.* Our 2017 capital expenditures, which include capitalized interest and overhead but exclude acquisitions, are expected to range between \$40 million and \$48 million, a 176% increase at the midpoint of that range from our spending in 2016, and are expected to be funded through cash flow from operations and cash on hand. Because we operate approximately 75% of our total estimated proved reserves and manage the drilling and completion activities on an additional 16% of such reserves, we expect to be able to control the timing of a substantial portion of our capital investments. We also may continue to opportunistically dispose of certain assets or enter into joint venture arrangements to provide additional liquidity and plan to maintain our commodity hedging program, as in prior years. As a result of the debt exchanges mentioned above and the suspension of the quarterly dividend payments on our outstanding Series B Preferred Stock, we expect to see cash savings on interest and dividends of approximately \$25 million during 2017.

*Pursue Balanced Growth and Portfolio Mix.* We plan to pursue a risk-balanced approach to the growth and stability of our reserves, production, cash flows and earnings. Our goal is to weight our capital allocation to lower risk development activities to balance the capital allocated to higher risk and higher impact exploration activities. We plan to allocate our capital investments in a manner that continues to geographically and operationally diversify our asset base. Through our portfolio diversification efforts, at December 31, 2016, approximately 72% of our estimated proved reserves were located in longer life and lower risk basins in East Texas and 28% were located in the shorter life, but higher flow rate reservoirs in the Gulf Coast Basin. In terms of production diversification, during 2016, 46% of our production was derived from longer life basins. Our 2016 production was comprised of 71% natural gas, 13% oil and 16% natural gas liquids.

*Focus Capital Toward More Predictable Onshore Assets.* We plan to focus the majority of our capital spending developing our lower-risk Cotton Valley acreage in East Texas. Since beginning horizontal drilling in the Carthage Field in 2011, we have a 100% drilling success rate on 20 gross wells drilled. Approximately 77% of our 2017 capital expenditures are allocated to operations in East Texas where we believe the less complex geology, combined with the large inventory of offsetting vertical and horizontal well data, offers greater predictability in increasing production and proved reserves. Additionally, our East Texas acreage position

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provides a significant inventory of future drilling locations, which we expect to develop over a long-term drilling campaign. We plan to apply the latest drilling and completion techniques to consistently improve the economic development of this resource potential.

*Concentrate in Core Operating Areas and Build Scale.* We plan to continue focusing on our operations in East Texas and the Gulf Coast Basin. Operating in concentrated areas helps to better control our overhead by enabling us to manage a greater amount of acreage with fewer employees and minimize incremental costs of increased drilling and production. We have substantial geological and reservoir data, operating experience and partner relationships in these regions. We believe that these factors, combined with the existing infrastructure and favorable geologic conditions with multiple known oil and gas producing reservoirs in these regions, will provide us with attractive investment opportunities.

*Manage Our Risk Exposure.* We plan to continue several strategies designed to mitigate our operating risks. We have adjusted the working interest we are willing to hold based on the risk level and cost exposure of each project. For example, we typically reduce our working interests in higher risk exploration projects while retaining greater working interests in lower risk development projects. Our partners often agree to pay a disproportionate share of drilling costs relative to their interests, allowing us to allocate our capital spending to maximize our return and reduce the inherent risk in exploration and development activities. We also strive to retain operating control of the majority of our properties to control costs and timing of expenditures and we expect to continue to actively hedge a portion of our future planned production to mitigate the impact of commodity price fluctuations and achieve more predictable cash flows. We may also enter into joint venture arrangements designed to develop our properties while limiting our capital requirements and preserving our liquidity.

### 2016 Financial and Operational Summary

During 2016, we invested \$15.9 million in exploratory, development and acquisition activities. We drilled 5 gross development wells realizing an overall success rate of 100%. These activities were financed through cash on hand and our cash flow from operations. During 2016, our production decreased 31% to 23.5 Bcfe as a result of the Oklahoma Divestitures and normal production declines at our East Texas and Gulf Coast fields. Our estimated proved reserves at December 31, 2016 decreased 35% from 2015 as discussed in greater detail below.

### Oil and Gas Reserves

Our estimated proved reserves at December 31, 2016 decreased 35% from 2015 totaling 1.4 MMBbls of oil, 26.6 Bcfe of natural gas liquids (Ngl) and 81 Bcf of natural gas. At December 31, 2016, our standardized measure of our discounted cash flows, which includes the estimated impact of future income taxes, totaled \$67.3 million. We had a pre-tax present value, discounted at 10%, of the estimated future net revenues based on 12-month, first day of month, average prices during 2016 ("PV-10") of \$67.3 million. The decrease in our estimated proved reserves during 2016 was primarily the result of the divestiture of our remaining Oklahoma assets, which represented 20 Bcfe of our estimated proved reserves as of December 31, 2015 as well as the 75% reduction in capital spending during 2016, as compared to 2015. See the reconciliation of standardized measure of discounted cash flows to PV-10 below. Our standardized measure of discounted cash flows and PV-10 utilized prices (adjusted for field differentials) for the years ended December 31, 2016 and 2015 as follows:

	<u>12/31/2016</u>	<u>12/31/2015</u>
Oil per Bbl	\$40.85	\$50.29
Natural gas per Mcf	\$2.40	\$2.41
Ngl per Mcfe	\$1.82	\$2.24

Ryder Scott Company, L.P., a nationally recognized independent petroleum engineering firm, prepared the estimates of our proved reserves and future net cash flows (and present value thereof) attributable to such proved reserves at December 31, 2016. Our internal reservoir engineering staff is managed by an individual with 35 years of industry experience as a reservoir and production engineer, including fourteen years as a reservoir engineering manager with PetroQuest. This individual is responsible for overseeing the estimates prepared by Ryder Scott.

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Our internal controls that are used in our reserve estimation process are designed to provide reasonable assurance that our reserve estimates are computed and reported in accordance with SEC rules and regulations and generally accepted accounting principles ("GAAP"). These internal controls are regularly tested in connection with our annual assessment of internal controls over financial reporting and include:

- Utilizing documented process workflows;
- Employing qualified professional engineering, geological, land, financial and marketing personnel; and
- Providing continuing education and training for all personnel involved in our reserve estimation process.

Each quarter, our Reservoir Engineering Manager presents the status of the changes to our reserve estimates to our executive team, including our Chief Executive Officer. These reserve estimates are then presented to our Board of Directors in connection with quarterly meetings. In addition, our reserve booking policies and procedures are reviewed annually by one of the members of our Board of Directors, acting on behalf of our Audit Committee.

With respect to proved undeveloped reserves ("PUD reserves"), we maintain a five year development plan that is updated and approved annually by our PUD Review Committee (as described below) with input from our executive team and asset managers and reviewed quarterly by our executive team and asset managers. Our development plan includes only PUDs that we are reasonably certain will be drilled within five years of booking based upon qualitative and quantitative factors including estimated risk-based returns, current pricing forecasts, recent drilling results, availability of services, equipment and personnel, seasonal weather patterns and changes in drilling and completion techniques and technology. Our PUD reserves are based upon our substantial basin-specific technical and operating experience relative to the location of the reserves. Over the last five years, we have realized a 100% drilling success rate on 20 gross wells drilled in East Texas where 100% of our PUD reserves are currently booked. Furthermore, because all of our longer life, onshore PUD reserves are direct offsetting locations to producing wells, we have comprehensive data available, which enables us to forecast economic results, including drilling and operating costs, with reasonable certainty.

During 2014, we established a committee that annually reviews our PUD reserves. Our PUD Review Committee (the "Committee") is comprised of our Executive Vice President of Operations, Chief Financial Officer and Reservoir Engineering Manager and meets annually in connection with each year-end reserve report. The Committee is responsible for reviewing all PUD locations, not only in terms of technical and financial merits as reviewed by our independent petroleum engineering firm, but also to apply a robust evaluation of the timing and reasonable certainty of the development plan in light of all known circumstances including our budget, the outlook for commodity prices and the location of ongoing drilling programs. The Committee's evaluation of reasonable certainty of the development plan includes a thorough assessment of near term drilling plans to develop PUDs, a review of adherence to previously adopted development plans and a review of historical PUD conversion rates.

The following table sets forth certain information about our estimated proved reserves as of December 31, 2016:

	Oil (MBbls)	NGL (Mmcfe)	Natural Gas (Mmcf)	Total Mmcfe*
Proved Developed	1,212	13,073	47,349	67,694
Proved Undeveloped	185	13,502	33,175	47,787
<b>Total Proved</b>	<b>1,397</b>	<b>26,575</b>	<b>80,524</b>	<b>115,481</b>

\* Oil conversion to Mcfe at one Bbl of crude oil, condensate or natural gas liquids to six Mcf of natural gas.

As of December 31, 2016, our PUD reserves totaled 47.8 Bcfe, a 36% decrease from our PUD reserves at December 31, 2015. During 2016, we spent \$2.1 million converting 5.4 Bcfe of PUD reserves at December 31, 2015 to proved developed reserves at December 31, 2016.

The following table presents an analysis of the change in our PUD reserves from December 31, 2015 to December 31, 2016:

	MMcfe
PUD Reserve balance at December 31, 2015	74,389
Conversions to proved developed	(5,392)
Divestitures	(6,524)
Revisions of previous estimates	(14,686)
<b>PUD Reserve balance at December 31, 2016</b>	<b>47,787</b>

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All of our PUD reserves at December 31, 2016 were associated with the future development of our East Texas properties. The revisions of previous estimates reflected in the table above include the reclassification of approximately 10.7 Bcfe of PUDs to probable reserves due to our expectation that those locations would not be developed within five years from initial booking. We expect all of our PUD reserves at December 31, 2016 to be developed over the next five years. However, our PUD reserve inventory does not encompass all drilling activities over the next five years. For example, during 2016 we converted 1.5 Bcfe of reserves that were classified as probable reserves at December 31, 2015 to proved developed producing at December 31, 2016 and therefore were not included in the above table. We expect to continue to allocate capital to projects that do not have proved reserves ascribed to them. At December 31, 2016, we had no PUD reserves booked for longer than five years. Estimated future costs related to the development of PUD reserves are expected to total \$13.5 million in 2017, \$4.3 million in 2018, \$14.6 million in 2019 and \$8.8 million in 2020. During 2017, we expect to convert approximately 18.1 Bcfe of PUDs at December 31, 2016 to proved developed reserves.

The estimated cash flows from our proved reserves at December 31, 2016 were as follows:

	Proved Developed (M\$)	Proved Undeveloped (M\$)	Total Proved (M\$)
Estimated pre-tax future net cash flows (1)	\$ 66,920	\$ 31,111	\$ 98,031
Discounted pre-tax future net cash flows (PV-10) (1)	\$ 57,709	\$ 9,560	\$ 67,269
Total standardized measure of discounted future net cash flows			\$ 67,269

- (1) Estimated pre-tax future net cash flows and discounted pre-tax future net cash flows (PV-10) are non-GAAP measures because they exclude income tax effects. Management believes these non-GAAP measures are useful to investors as they are based on prices, costs and discount factors which are consistent from company to company, while the standardized measure of discounted future net cash flows is dependent on the unique tax situation of each individual company. As a result, the Company believes that investors can use these non-GAAP measures as a basis for comparison of the relative size and value of the Company's reserves to other companies. The Company also understands that securities analysts and rating agencies use these non-GAAP measures in similar ways.

The following table reconciles undiscounted and discounted future net cash flows to standardized measure of discounted cash flows as of December 31, 2016:

	Total Proved (M\$)
Estimated pre-tax future net cash flows	\$ 98,031
10% annual discount	30,762
Discounted pre-tax future net cash flows	67,269
Future income taxes discounted at 10%	—
Standardized Measure of discounted future net cash flows	\$ 67,269

We have not filed any reports with other federal agencies that contain an estimate of total proved net oil and gas reserves.

## Core Areas

The following table sets forth estimated proved reserves and annual production from each of our core areas (in Bcfe) for the years ended December 31, 2016 and 2015.

	2016		2015	
	Reserves	Production	Reserves	Production
Gulf Coast Basin	32.9	12.8	43.9	13.8
East Texas	82.6	9.0	114.1	11.1
Oklahoma Woodford (1)	—	1.7	20.0	9.2
Other	—	—	—	0.1
	115.5	23.5	178.0	34.2

- (1) In June 2015, we divested the majority of our Oklahoma Woodford assets (representing 227.2 Bcfe of proved reserves at December 31, 2014) which contributed 7.0 Bcfe of production in 2015. In April and October 2016, we divested the remainder of our Oklahoma assets (representing 20 Bcfe of proved reserves at December 31, 2015) which contributed 1.7 Bcfe of production in 2016.

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### *East Texas*

During 2016, we invested \$3.9 million in our East Texas properties where we drilled one gross well, achieving a 100% success rate. Net production from our East Texas assets averaged 24.7 MMcfe per day during 2016, a 19% decrease from 2015 average daily production, and our estimated proved reserves decreased 28% from 2015 due to the reduced capital spending in this core area during 2016 as well as the reclassification of certain PUD reserves to probable reserves. We have allocated approximately 77% of our 2017 capital budget to drilling and performing various re-completions at our Carthage Field.

### *Gulf Coast Basin*

During 2016, we invested \$6.1 million in this core area. Production from this area decreased 8% from 2015 totaling 34.9 MMcfe per day in 2016 due to normal production declines in the Gulf Coast area offset by a full year of production from our Thunder Bayou discovery. Our estimated proved reserves in this area decreased 25% from 2015 primarily as a result of the 12.8 Bcfe of production in 2016. We have allocated approximately 23% of our 2017 capital budget to performing various re-completions and plugging and abandonment projects in the Gulf Coast Basin.

### *Oklahoma - Woodford*

During 2016, we invested \$0.3 million and completed four gross wells, achieving a 100% success rate. Average daily production from our Oklahoma properties during 2016 totaled 5 MMcfe per day, an 82% decrease from 2015 average daily production primarily as a result of the Oklahoma Divestitures. During 2016, we sold 21.9 Bcfe of proved reserves in connection with our exit from this core area.

## **Markets and Customers**

We sell our oil and natural gas production under fixed or floating market contracts. Customers purchase all of our oil and natural gas production at current market prices. The terms of the arrangements generally require customers to pay us within 30 days after the production month ends. As a result, if the customers were to default on their payment obligations to us, near-term earnings and cash flows would be adversely affected. However, due to the availability of other markets and pipeline connections, we do not believe that the loss of these customers or any other single customer would adversely affect our ability to market production. Our ability to market oil and natural gas from our wells depends upon numerous factors beyond our control, including:

- the extent of domestic production and imports of oil and natural gas;
- the proximity of the natural gas production to pipelines;
- the availability of capacity in such pipelines;
- the demand for oil and natural gas by utilities and other end users;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- state and federal regulation of oil and natural gas production; and
- federal regulation of gas sold or transported in interstate commerce.

We cannot assure you that we will be able to market all of the oil or natural gas we produce or that favorable prices can be obtained for the oil and natural gas we produce.

A portion of the natural gas production that we operate in East Texas is committed to a minimum volumetric delivery contract with a third party pipeline company. Under the terms of the agreement, we are required to deliver 11.0 Bcfe of natural gas during the eighteen-month period from July 1, 2017 through December 31, 2018 and each of the twelve-month periods ended December 31, 2019, 2020 and 2021, respectively. Based upon our projected drilling plans, current estimated proved developed reserves and production, we expect that this commitment will be met.

In view of the many uncertainties affecting the supply and demand for oil, natural gas and refined petroleum products, we are unable to predict future oil and natural gas prices and demand or the overall effect such prices and demand will have on the Company. During 2016, one customer accounted for 23%, one accounted for 17%, one accounted for 14% and one accounted for 10% of our oil and natural gas revenue. During 2015, one customer accounted for 21%, one accounted for 18%, one accounted

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for 17% and one accounted for 10% of our oil and natural gas revenue. During 2014, one customer accounted for 30%, one accounted for 24% and one accounted for 14% of our oil and natural gas revenue. These percentages do not consider the effects of commodity hedges. We do not believe that the loss of any of our oil or natural gas purchasers would have a material adverse effect on our operations due to the availability of other purchasers.



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### Production, Pricing and Production Cost Data

The following table sets forth our production, pricing and production cost data during the periods indicated. Our remaining core areas, Gulf Coast Basin and East Texas, both represented approximately 15% or more of our total estimated proved reserves at December 31, 2016.

	Year Ended December 31,		
	2016	2015	2014
<b>Production:</b>			
Oil (Bbls):			
Gulf Coast Basin	463,903	473,846	687,855
East Texas	38,154	50,739	62,013
Other (3)	144	3,944	52,641
Total Oil (Bbls)	<u>502,201</u>	<u>528,529</u>	<u>802,509</u>
Gas (Mcf):			
Gulf Coast Basin	8,596,488	9,421,031	10,825,424
East Texas	6,350,712	7,838,144	6,636,174
Other (3)	1,669,378	8,242,676	13,566,073
Total Gas (Mcf)	<u>16,616,578</u>	<u>25,501,851</u>	<u>31,027,671</u>
NGL (Mcf):			
Gulf Coast Basin	1,395,614	1,548,228	1,325,288
East Texas	2,471,936	2,946,185	2,672,885
Other (3)	3,397	992,826	3,484,137
Total NGL (Mcf)	<u>3,870,947</u>	<u>5,487,239</u>	<u>7,482,310</u>
Total Production (Mcf):			
Gulf Coast Basin	12,775,520	13,812,335	16,277,842
East Texas	9,051,572	11,088,763	9,681,137
Other (3)	1,673,639	9,259,166	17,366,056
Total Production (Mcf)	<u>23,500,731</u>	<u>34,160,264</u>	<u>43,325,035</u>
Average sales prices (1):			
Oil (per Bbl):			
Gulf Coast Basin	\$ 41.27	\$ 48.94	\$ 96.71
East Texas	38.35	48.28	92.21
Other (3)	37.85	50.88	95.74
Total Oil (per Bbl)	41.05	48.89	96.30
Gas (per Mcf)			
Gulf Coast Basin	2.27	2.55	4.38
East Texas	2.31	2.63	4.08
Other (3)	1.17	1.75	3.27
Total Gas (per Mcf)	2.18	2.32	3.83
NGL (per Mcfe)			
Gulf Coast Basin	3.12	3.03	6.00
East Texas	1.50	1.94	4.17
Other (3)	5.22	3.49	3.68
Total NGL (per Mcfe)	2.09	2.53	4.27
Total Per Mcfe:			
Gulf Coast Basin	3.37	3.76	7.49
East Texas	2.19	2.60	4.54
Other (3)	1.18	1.96	3.59
Total Per Mcfe	2.76	2.89	5.26
Average Production Cost per Mcfe (2):			
Gulf Coast Basin	1.50	1.86	1.59
East Texas	0.88	0.90	1.21
Other (3)	0.80	0.48	0.63
Total Average Production Cost per Mcfe	1.21	1.17	1.12

(1) Does not include the effect of hedges.

(2) Production costs do not include production taxes.

(3) Includes Oklahoma-Woodford.

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### Oil and Gas Producing Wells

The following table details the productive wells in which we owned an interest as of December 31, 2016:

	Gross	Net
<b>Productive Wells:</b>		
<b>Oil:</b>		
Gulf Coast Basin	17	9.43
East Texas	—	—
	<u>17</u>	<u>9.43</u>
<b>Gas:</b>		
Gulf Coast Basin	12	6.82
East Texas	71	44.53
	<u>83</u>	<u>51.35</u>
<b>Total</b>	<u><u>100</u></u>	<u><u>60.78</u></u>

Of the 100 gross productive wells at December 31, 2016, one had a dual completion.

### Oil and Gas Drilling Activity

The following table sets forth the wells drilled and completed by us during the periods indicated. All wells were drilled in the continental United States.

	2016		2015		2014	
	Gross	Net	Gross	Net	Gross	Net
<b>Exploration:</b>						
<b>Productive:</b>						
Gulf Coast Basin	—	—	—	—	2	1.19
East Texas	—	—	4	3.31	4	3.10
Other (1)	—	—	22	5.05	19	7.14
	<u>—</u>	<u>—</u>	<u>26</u>	<u>8.36</u>	<u>25</u>	<u>11.43</u>
<b>Non-productive:</b>						
Gulf Coast Basin	—	—	3	1.22	2	1.12
East Texas	—	—	—	—	—	—
Other (1)	—	—	—	—	2	2.00
	<u>—</u>	<u>—</u>	<u>3</u>	<u>1.22</u>	<u>4</u>	<u>3.12</u>
<b>Total</b>	<u><u>—</u></u>	<u><u>—</u></u>	<u><u>29</u></u>	<u><u>9.58</u></u>	<u><u>29</u></u>	<u><u>14.55</u></u>
<b>Development:</b>						
<b>Productive:</b>						
Gulf Coast Basin	—	—	—	—	—	—
East Texas	1	0.81	—	—	2	1.55
Other (1)	4	0.02	27	4.30	26	6.05
	<u>5</u>	<u>0.83</u>	<u>27</u>	<u>4.30</u>	<u>28</u>	<u>7.60</u>
<b>Non-productive:</b>						
Gulf Coast Basin	—	—	—	—	—	—
East Texas	—	—	—	—	—	—
Other (1)	—	—	—	—	1	0.50
	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>1</u>	<u>0.50</u>
<b>Total</b>	<u><u>5</u></u>	<u><u>0.83</u></u>	<u><u>27</u></u>	<u><u>4.30</u></u>	<u><u>29</u></u>	<u><u>8.10</u></u>

(1) Includes Oklahoma-Woodford.

At December 31, 2016, we had 2 gross (1.26 net) wells in progress.

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### Leasehold Acreage

The following table shows our approximate developed and undeveloped (gross and net) leasehold acreage as of December 31, 2016:

	Leasehold Acreage			
	Developed		Undeveloped	
	Gross	Net	Gross	Net
Kansas	—	—	160	80
Louisiana	4,378	1,550	731	78
Texas	39,803	20,860	9,844	5,896
Federal Waters	31,532	23,198	6,420	6,420
Total	75,713	45,608	17,155	12,474

Leases covering 5% of our net undeveloped acreage are scheduled to expire in 2017, 9% in 2018, 5% in 2019 and 82% thereafter. At December 31, 2016, we do not have any PUD reserves attributed to acreage that has an expiration date preceding the scheduled date for initial development. Of the acreage subject to leases scheduled to expire during 2017, 84% relates to undeveloped acreage in the Carthage area in East Texas where we plan to drill eight to ten wells during 2017.

### Title to Properties

Title to properties is subject to contractual arrangements customary in the oil and gas industry, liens for taxes not yet due and, in some instances, other encumbrances. We believe that such burdens do not materially detract from the value of properties or from the respective interests therein or materially interfere with their use in the operation of the business.

As is customary in the industry, other than a preliminary review of local records, little investigation of record title is made at the time of acquisitions of undeveloped properties. Investigations, which generally include a title opinion of outside counsel, are made prior to the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Our properties are typically subject, in one degree or another, to one or more of the following:

- royalties and other burdens and obligations, express or implied, under oil and gas leases;
- overriding royalties and other burdens created by us or our predecessors in title;
- a variety of contractual obligations (including, in some cases, development obligations) arising under operating agreements, farmout agreements, production sales contracts and other agreements that may affect the properties or their titles;
- back-ins and reversionary interests existing under purchase agreements and leasehold assignments;
- liens that arise in the normal course of operations, such as those for unpaid taxes, statutory liens securing obligations to unpaid suppliers and contractors and contractual liens under operating agreements; pooling, unitization and communitization agreements, declarations and orders; and
- easements, restrictions, rights-of-way and other matters that commonly affect property.

To the extent that such burdens and obligations affect our rights to production revenues, they have been taken into account in calculating our net revenue interests and in estimating the size and value of our reserves. We believe that the burdens and obligations affecting our properties are conventional in the industry for properties of the kind that we own.

### Federal Regulations

**Sales and Transportation of Natural Gas.** Historically, the transportation and sales for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938 (“NGA”), the Natural Gas Policy Act of 1978 and the Federal Energy Regulatory Commission (“FERC”) regulations. Effective January 1, 1993, the Natural Gas Wellhead Decontrol Act deregulated the price for all “first sales” of natural gas. Thus, all of our sales of gas may be made at market prices, subject to applicable contract provisions. Sales of natural gas are affected by the availability, terms and cost of pipeline transportation. Since 1985, the FERC has implemented regulations intended to make natural gas transportation more accessible to gas buyers and sellers on an open-access, non-discriminatory basis. We cannot predict what further action the FERC will take on these matters. Some of the FERC's more recent proposals may, however, adversely affect the availability and reliability of interruptible transportation

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service on interstate pipelines. We do not believe that we will be affected by any action taken materially differently than other natural gas producers, gatherers and marketers with which we compete.

The Outer Continental Shelf Lands Act (the "OCSLA"), which was administered by the Bureau of Ocean Energy Management, Regulation and Enforcement (the "BOEMRE") and, after October 1, 2011, its successors, the Bureau of Ocean Energy Management (the "BOEM") the Bureau of Safety and Environmental Enforcement (the "BSEE"), and the FERC, requires that all pipelines operating on or across the shelf provide open-access, non-discriminatory service. There are currently no regulations implemented by the FERC under its OCSLA authority on gatherers and other entities outside the reach of its NGA jurisdiction. Therefore, we do not believe that any FERC, BOEM or BSEE action taken under OCSLA will affect us in a way that materially differs from the way it affects other natural gas producers, gatherers and marketers with which we compete.

Our natural gas sales are generally made at the prevailing market price at the time of sale. Therefore, even though we sell significant volumes to major purchasers, we believe that other purchasers would be willing to buy our natural gas at comparable market prices.

Natural gas continues to supply a significant portion of North America's energy needs and we believe the importance of natural gas in meeting this energy need will continue. The impact of the sudden drop in crude oil prices has not yet had a significant impact on gas prices, but a continued drop in crude oil prices could eventually impact gas markets. At this time, we are not in a position to predict the scope of any loss of market due to lower crude oil prices.

On August 8, 2005, the Energy Policy Act of 2005 (the "2005 EPA") was signed into law. This comprehensive act contains many provisions that intended to encourage oil and gas exploration and development in the U.S. The 2005 EPA directs the FERC, BOEM and other federal agencies to issue regulations that will further the goals set out in the 2005 EPA. The 2005 EPA amends the NGA to make it unlawful for "any entity", including otherwise non-jurisdictional producers such as us, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the FERC, in contravention of rules prescribed by the FERC. On January 20, 2006, the FERC issued rules implementing this provision. The rules make it unlawful in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. The new anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction. It therefore reflects a significant expansion of the FERC's enforcement authority. To date, we do not believe we have been, nor do we anticipate we will be affected any differently than other producers of natural gas.

In 2007, the FERC issued a final rule on annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing ("Order 704"). Under Order 704, wholesale buyers and sellers of more than 2.2 million MMBtu of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors and natural gas marketers are now required to report, on May 1 of each year, beginning in 2009, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. The monitoring and reporting required by these rules have increased our administrative costs. To date, we do not believe we have been, nor do we anticipate that we will be affected any differently than other producers of natural gas.

**Sales and Transportation of Crude Oil.** The spot markets for oil, gas and natural gas liquids ("NGLs") are subject to volatility and supply and demand factors fluctuations. Our sales of crude oil, condensate and natural gas liquids are not currently regulated, and are subject to applicable contract provisions made at market prices and typically under short term agreements with third parties. Additionally, we may periodically enter into financial hedging arrangements or fixed-price contracts associated with a portion of our oil, gas or natural gas liquids production. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to the FERC's jurisdiction under the Interstate Commerce Act. In other instances, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to regulation by state regulatory bodies under state statutes.

The regulation of pipelines that transport crude oil, condensate and natural gas liquids is generally more light-handed than the FERC's regulation of gas pipelines under the NGA. Regulated pipelines that transport crude oil, condensate, and natural gas liquids are subject to common carrier obligations that generally ensure non-discriminatory access. With respect to interstate pipeline transportation subject to regulation of the FERC under the Interstate Commerce Act, rates generally must be cost-based, although market-based rates or negotiated settlement rates are permitted in certain circumstances. Pursuant to FERC Order No. 561, pipeline rates are subject to an indexing methodology. Under this indexing methodology, pipeline rates are subject to changes in

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the Producer Price Index for Finished Goods, minus one percent. A pipeline can seek to increase its rates above index levels provided that the pipeline can establish that there is a substantial divergence between the actual costs experienced by the pipeline and the rate resulting from application of the index. A pipeline can seek to charge market based rates if it establishes that it lacks significant market power. In addition, a pipeline can establish rates pursuant to settlement if agreed upon by all current shippers. A pipeline can seek to establish initial rates for new services through a cost-of-service proceeding, a market-based rate proceeding, or through an agreement between the pipeline and at least one shipper not affiliated with the pipeline.

**Federal Leases.** We maintain operations located on federal oil and natural gas leases, which are administered by the BOEM or the BSEE, pursuant to the OCSLA. The BOEM and the BSEE regulate offshore operations, including engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells on the Gulf of Mexico shelf, and removal of facilities.

The BOEM handles offshore leasing, resource evaluation, review and administration of oil and gas exploration and development plans, renewable energy development, National Environmental Policy Act analysis and environmental studies, and the BSEE is responsible for the safety and enforcement functions of offshore oil and gas operations, including the development and enforcement of safety and environmental regulations, permitting of offshore exploration, development and production activities, inspections, offshore regulatory programs, oil spill response and newly formed training and environmental compliance programs. Our federal oil and natural gas leases are awarded based on competitive bidding and contain relatively standardized terms. These leases require compliance with detailed regulations and orders that are subject to interpretation and change by the BOEM or BSEE. We are currently subject to regulations governing the plugging and abandonment of wells located offshore and the installation and removal of all production facilities, structures and pipelines, and the BOEM or the BSEE may in the future amend these regulations. Please read "Risk Factors" beginning on page 20 for more information on new regulations.

To cover the various obligations of lessees on the Outer Continental Shelf (the "OCS"), the BOEM generally requires that lessees have substantial net worth or post bonds or other acceptable assurances that such obligations will be satisfied. While we have been exempt from such supplemental bonding requirements in the past, beginning in 2014 we were required to post supplemental bonding or alternate form of collateral for certain of our offshore properties. We have been able to satisfy the collateral requirements using a combination of our existing cash on hand and the issuance of supplemental bonds. Under some circumstances, the BOEM may require any of our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially adversely affect our financial condition and results of operations. As a result of certain bankruptcies of Gulf of Mexico operations, BSEE and BOEM are currently reassessing decommissioning liability and supplemental bonding requirements for all operations on the Gulf of Mexico OCS with respect to decommissioning wells and platforms in the Gulf of Mexico and are updating all decommissioning costs in the Gulf of Mexico. The Department of the Interior through the BOEM and BSEE has made enforcement of decommissioning liabilities one of its top priorities. Recent Department of Interior guidance has indicated that well abandonment and decommissioning requirements are not necessarily tied to lease termination. Based on the ongoing review of such decommissioning and abandonment costs, the Company's potential liability for such costs has become more expensive and as a result supplemental bonding costs may continue to increase, which along with any future directives or changes to BOEM's current supplemental bonding requirements, could materially and adversely affect our financial condition, cash flows, and results of operations. Because we are not exempt from the BOEM's supplemental bonding requirements, we engage a number of surety companies to post the requisite bonds. Pursuant to the terms of our agreements with these surety companies, we are required to post collateral at the outset of the agreement or subsequently on demand, the amount of which typically may be increased at the surety companies' discretion. Two of our surety companies requested that we post collateral to support certain of the bonds that are issued on our behalf and to date, we have provided cash deposits totaling \$6.2 million to satisfy these requests. We cannot assure you that we will be able to satisfy future demands for collateral for the requisite bonds or comply with new supplemental bonding requirements. If we fail to do so, we may be in default under the Multidraw Term Loan Agreement and potentially the indentures governing the 10% second-lien senior secured notes due 2021 (the "2021 Notes") and the 10% second lien senior secured PIK notes due 2021 (the "2021 PIK Notes").

In addition, on July 14, 2016, the BOEM issued a notice to lessees ("NTL") No. 2016-N01 effective September 12, 2016 to clarify the procedures and criteria that the BOEM will use to determine if and when additional security is required for OCS leases. This notice may result in an increase to the amount of surety bonds or other security required to be posted by us pursuant to these updated BOEM financial assurance and risk management requirements. On January 6, 2017, the BOEM announced that it was extending the implementation timeline for NTL No. 2016-N01 by an additional six months as to leases, rights-of-way and rights of use and easement for which there are co-lessees and/or predecessors in interest, except in circumstances in which the BOEM determines there is a substantial risk of nonperformance of the interest holder's decommissioning liabilities. All of our decommissioning liabilities as of the date hereof have co-lessees and/or predecessors in interest and are expected to be included in this extended implementation timeline. We can provide no assurance that we can continue to obtain bonds or other surety in all cases given these new expenses and updated BOEM requirements or that we will have sufficient liquidity to support such supplemental bonding requirements. If we are unable to obtain the additional required bonds, assurances or the increased amount of required collateral as requested, the BOEM may require any of our operations on federal leases to be suspended, canceled or

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otherwise impose monetary penalties, and one or more of such actions could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity.

Hurricanes in the Gulf of Mexico can have a significant impact on oil and gas operations on the OCS. The effects from past hurricanes have included structural damage to pipelines, wells, fixed production facilities, semi-submersibles and jack-up drilling rigs. The BOEM and the BSEE will continue to be concerned about the loss of these facilities and rigs as well as the potential for catastrophic damage to key infrastructure and the resultant pollution from future storms. In an effort to reduce the potential for future damage, the BOEMRE historically issued guidance aimed at improving platform survivability by taking into account environmental and oceanic conditions in the design of platforms and related structures. It is possible that similar, if not more stringent, requirements will be issued by the BOEM or the BSEE for future hurricane seasons. New requirements, if any, could increase our operating costs due to future storms.

The Office of Natural Resources Revenue (the “ONRR”) in the U.S. Department of the Interior administers the collection of royalties under the terms of the OCSLA and the oil and natural gas leases issued thereunder. The amount of royalties due is based upon the terms of the oil and natural gas leases as well as the regulations promulgated by the ONRR.

**Federal, State or American Indian Leases.** In the event we conduct operations on federal, state or American Indian oil and gas leases, such operations must comply with numerous regulatory restrictions, including various nondiscrimination statutes, and certain of such operations must be conducted pursuant to certain on-site security regulations and other appropriate permits issued by the Bureau of Land Management (“BLM”) or the BOEM or other appropriate federal or state agencies.

The Mineral Leasing Act of 1920 (“Mineral Act”) prohibits direct or indirect ownership of any interest in federal onshore oil and gas leases by a foreign citizen of a country that denies “similar or like privileges” to citizens of the United States. Such restrictions on citizens of a “non-reciprocal” country include ownership of holding or controlling stock in a corporation that holds a federal onshore oil and gas lease. If this restriction is violated, the corporation's lease can be cancelled in a proceeding instituted by the United States Attorney General. Although the regulations of the BLM (which administers the Mineral Act) provide for agency designations of non-reciprocal countries, there are presently no such designations in effect. We own interests in numerous federal onshore oil and gas leases. It is possible that holders of our equity interests may be citizens of foreign countries, which at some time in the future might be determined to be non-reciprocal under the Mineral Act.

## State Regulations

Most states regulate the production and sale of oil and natural gas, including:

- requirements for obtaining drilling permits;
- the method of developing new fields;
- the spacing and operation of wells;
- the prevention of waste of oil and gas resources; and
- the plugging and abandonment of wells.

The rate of production may be regulated and the maximum daily production allowable from both oil and gas wells may be established on a market demand or conservation basis or both.

We may enter into agreements relating to the construction or operation of a pipeline system for the transportation of natural gas. To the extent that such gas is produced, transported and consumed wholly within one state, such operations may, in certain instances, be subject to the jurisdiction of such state’s administrative authority charged with the responsibility of regulating intrastate pipelines. In such event, the rates that we could charge for gas, the transportation of gas, and the construction and operation of such pipeline would be subject to the rules and regulations governing such matters, if any, of such administrative authority.

## Legislative Proposals

In the past, Congress has been very active in the area of natural gas regulation. New legislative proposals in Congress and the various state legislatures, if enacted, could significantly affect the petroleum industry. At the present time it is impossible to predict what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, such proposals might have on our operations.

### Environmental Regulations

**General.** Our activities are subject to existing federal, state and local laws and regulations governing environmental quality and pollution control. Although no assurances can be made, we believe that, absent the occurrence of an extraordinary event, compliance with existing federal, state and local laws, regulations and rules regulating the release of materials into the environment or otherwise relating to the protection of human health, safety and the environment will not have a material effect upon our capital expenditures, earnings or competitive position with respect to our existing assets and operations. We cannot predict what effect additional regulation or legislation, enforcement policies, and claims for damages to property, employees, other persons and the environment resulting from our operations could have on our activities.

Our activities with respect to exploration and production of oil and natural gas, including the drilling of wells and the operation and construction of pipelines and other facilities for extracting, transporting or storing natural gas and other petroleum products, are subject to stringent environmental regulation by state and federal authorities, including the United States Environmental Protection Agency (the "USEPA"). Such regulation can increase the cost of planning, designing, installing and operating such facilities. Although we believe that compliance with environmental regulations will not have a material adverse effect on us, risks of substantial costs and liabilities are inherent in oil and gas production operations, and there can be no assurance that significant costs and liabilities will not be incurred. Moreover it is possible that other developments, such as spills or other unanticipated releases, stricter environmental laws and regulations, and claims for damages to property or persons resulting from oil and gas production, would result in substantial costs and liabilities to us.

**Solid and Hazardous Waste.** We own or lease numerous properties that have been used for production of oil and gas for many years. Although we have utilized operating and disposal practices standard in the industry at the time, hydrocarbons or solid wastes may have been disposed or released on or under these properties. In addition, many of these properties have been operated by third parties that controlled the treatment of hydrocarbons or solid wastes and the manner in which such substances may have been disposed or released. State and federal laws applicable to oil and gas wastes and properties have gradually become stricter over time. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators) or to perform remedial plugging operations to prevent future contamination.

Wastes, including hazardous wastes, are subject to regulation under the federal Resource Conservation and Recovery Act ("RCRA") and state statutes. Much of the waste we generate in our operations at exploration and production sites, including hazardous waste, is exempt from regulation under RCRA, but generally remains subject to state storage, treatment and disposal requirements. We also generate wastes not subject to the RCRA exemption. The USEPA has limited the disposal options for certain hazardous wastes. It is possible that certain wastes generated by our oil and gas operations which are currently exempt from regulation under RCRA as "hazardous wastes" may in the future be designated as "hazardous wastes" under RCRA or other applicable statutes, and therefore be subject to more rigorous and costly disposal requirements.

Naturally Occurring Radioactive Materials ("NORM") are radioactive materials which precipitate on production equipment or area soils during oil and natural gas extraction or processing. NORM wastes are regulated under the RCRA framework, although such wastes may qualify for the oil and gas hazardous waste exclusion. Primary responsibility for NORM regulation has been a state function. Standards have been developed for worker protection; treatment, storage and disposal of NORM waste; management of waste piles, containers and tanks; and limitations upon the release of NORM-contaminated land for unrestricted use. We believe that our operations are in material compliance with all applicable NORM standards.

**Superfund.** The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, imposes liability, without regard to fault or the legality of the original conduct, on certain persons with respect to the release or threatened release of a "hazardous substance" into the environment. These persons include the owner and operator of a site and persons that disposed or arranged for the disposal of hazardous substances at a site. CERCLA also authorizes the USEPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the responsible persons the costs of such action. State statutes impose similar liability.

Under CERCLA, the term "hazardous substance" does not include "petroleum, including crude oil or any fraction thereof," unless specifically listed or designated and the term does not include natural gas, natural gas liquids, liquefied natural gas, or synthetic gas usable for fuel. While this "petroleum exclusion" lessens the significance of CERCLA to our operations, we may generate waste that may fall within CERCLA's definition of a "hazardous substance" in the course of our ordinary operations. We also currently own or lease properties that for many years have been used for the exploration and production of oil and natural gas. Although we and, to our knowledge, our predecessors have used operating and disposal practices that were standard in the industry at the time, "hazardous substances" may have been disposed or released on, under or from the properties owned or leased by us or on, under or from other locations where these wastes have been taken for disposal. At this time, we do not believe that we have any liability associated with any Superfund site, and we have not been notified of any claim, liability or damages under CERCLA.

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**Endangered Species Act.** Federal and state legislation including, in particular, the federal Endangered Species Act of 1973 (“ESA”), impose requirements to protect imperiled species from extinction by conserving and protecting threatened and endangered species and the habitat upon which they depend. With specified exceptions, the ESA prohibits the “taking,” including killing, harassing or harming, of any listed threatened or endangered species, as well as any degradation or destruction of its habitat. In addition, the ESA mandates that federal agencies carry out programs for conservation of listed species. Many state laws similarly protect threatened and endangered species and their habitat. We operate in areas in which listed species may be present. As a result, we may be required to adopt protective measures, obtain incidental take permits, and otherwise adjust our drilling plans to comply with ESA requirements.

**Oil Pollution Act.** The Oil Pollution Act of 1990 (the “OPA”) and regulations thereunder impose a variety of requirements on “responsible parties” related to the prevention of oil spills and liability for damages resulting from such spills in United States waters. A “responsible party” includes the owner or operator of a facility or vessel, or the lessee or permittee of the area in which an offshore facility is located. The OPA assigns liability to each responsible party for oil removal costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of federal safety, construction or operating regulations. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by the OPA.

The OPA establishes a liability limit for onshore facilities of \$633.8 million and for offshore facilities of all removal costs plus \$133.65 million, and lesser limits for some vessels depending upon their size. The regulations promulgated under OPA impose proof of financial responsibility requirements that can be satisfied through insurance, guarantee, indemnity, surety bond, letter of credit, qualification as a self-insurer, or a combination thereof. The amount of financial responsibility required depends upon a variety of factors including the type of facility or vessel, its size, storage capacity, oil throughput, proximity to sensitive areas, type of oil handled, history of discharges and other factors. We carry insurance coverage to meet these obligations, which we believe is customary for comparable companies in our industry. A failure to comply with OPA’s requirements or inadequate cooperation during a spill response action may subject a responsible party to civil or criminal enforcement actions.

As a result of the explosion and sinking of the Deepwater Horizon drilling rig in the Gulf of Mexico in 2010, Congress considered but did not enact legislation that would eliminate the current cap on liability for damages and increase minimum levels of financial responsibility under OPA. If enacted, such legislation could increase our obligations and potential liability, but adoption of such legislation is uncertain. We are not aware of the occurrence of any action or event that would subject us to liability under OPA, and we believe that compliance with OPA’s financial responsibility and other operating requirements will not have a material adverse effect on us.

**Discharges.** The Clean Water Act (“CWA”) regulates the discharge of pollutants to waters of the United States, including wetlands, and requires a permit for the discharge of pollutants, including petroleum, to such waters. The CWA also requires a permit for the discharge of dredged or fill material into wetlands. A revised regulatory definition of “Waters of the United States” that would expand requirements for CWA permitting, has been promulgated, but these regulations have been stayed pending the outcome of judicial challenges. Certain facilities that store or otherwise handle oil are required to prepare and implement Spill Prevention, Control and Countermeasure Plans and Facility Response Plans relating to the possible discharge of oil to surface waters. We are required to prepare and comply with such plans and to obtain and comply with discharge permits. We believe we are in substantial compliance with these requirements and that any noncompliance would not have a material adverse effect on us. The CWA also prohibits spills of oil and hazardous substances to waters of the United States in excess of levels set by regulations and imposes liability in the event of a spill. State laws further provide civil and criminal penalties and liabilities for spills to both surface and groundwaters and require permits that set limits on discharges to such waters.

**Hydraulic Fracturing.** Our exploration and production activities may involve the use of hydraulic fracturing techniques to stimulate wells and maximize natural gas production. Citing concerns over the potential for hydraulic fracturing to impact drinking water, human health and the environment, and in response to a Congressional directive, the USEPA commissioned a study to identify potential risks associated with hydraulic fracturing and to improve scientific understanding to guide USEPA’s regulatory oversight, guidance and, where appropriate, rulemaking related to hydraulic fracturing. A final report for this study was released in December 2016 and provided information regarding potential vulnerability of drinking water resources to hydraulic fracturing, but did not reach conclusions regarding the frequency or severity of impacts due to data gaps and uncertainties. Some states now regulate utilization of hydraulic fracturing and others are in the process of developing, or are considering development of, such rules to address the potential for drinking water impacts, induced seismicity, and other concerns. In several localities and in New York, use of hydraulic fracturing has been banned, although local fracking bans are prohibited in Texas and Louisiana. These states currently address hydraulic fracturing concerns by requiring disclosures of the content of fluids used in the process. Our drilling activities could be subjected to new or enhanced federal, state and/or local requirements governing hydraulic fracturing.

**Air Emissions.** Our operations are subject to local, state and federal regulations for the control of emissions from sources of air pollution. Administrative enforcement actions for failure to comply strictly with air regulations or permits may be resolved



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by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could impose civil or criminal liability for non-compliance. An agency could require us to forego construction or operation of certain air emission sources. We believe that we are in substantial compliance with air pollution control requirements.

According to certain scientific studies, emissions of carbon dioxide, methane, nitrous oxide and other gases commonly known as greenhouse gases (“GHG”) may be contributing to global warming of the earth’s atmosphere and to global climate change. In response to the scientific studies, legislative and regulatory initiatives have been underway to limit GHG emissions. The U.S. Supreme Court determined that GHG emissions fall within the federal Clean Air Act (“CAA”) definition of an “air pollutant”, and in response the USEPA promulgated an endangerment finding paving the way for regulation of GHG emissions under the CAA. The USEPA has also promulgated rules requiring large sources to report their GHG emissions. Sources subject to these reporting requirements include on- and offshore petroleum and natural gas production and onshore natural gas processing and distribution facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year in aggregate emissions from all site sources. We are not subject to GHG reporting requirements. In addition, the USEPA promulgated rules that significantly increase the GHG emission threshold that would identify major stationary sources of GHG subject to CAA permitting programs. As currently written and based on current Company operations, we are not subject to federal GHG permitting requirements. Regulation of GHG emissions is developing and highly controversial, and further regulatory, legislative and judicial developments are likely to occur. Such developments may affect how these GHG initiatives will impact the Company. Due to the uncertainties surrounding the regulation of and other risks associated with GHG emissions, the Company cannot predict the financial impact of related developments on the Company.

The USEPA has promulgated rules to limit air emissions from many hydraulically fractured natural gas wells. These regulations require use of equipment to capture gases that come from the well during the drilling process, mandate tighter standards for emissions associated with gas production, storage and transport, and seek to limit flaring. Such regulations have been highly controversial, have been challenged, and their future is uncertain. While such requirements would be expected to increase the cost of natural gas production, we do not anticipate that we will be affected any differently than other producers of natural gas.

**Coastal Coordination.** There are various federal and state programs that regulate the conservation and development of coastal resources. The federal Coastal Zone Management Act (“CZMA”) was passed to preserve and, where possible, restore the natural resources of the Nation’s coastal zone. The CZMA provides for federal grants for state management programs that regulate land use, water use and coastal development.

The Louisiana Coastal Zone Management Program (“LCZMP”) was established to protect, develop and, where feasible, restore and enhance coastal resources of the state. Under the LCZMP, coastal use permits are required for certain activities, even if the activity only partially infringes on the coastal zone. Among other things, projects involving use of state lands and water bottoms, dredge or fill activities that intersect with more than one body of water, mineral activities, including the exploration and production of oil and gas, and pipelines for the gathering, transportation or transmission of oil, gas and other minerals require such permits. General permits, which entail a reduced administrative burden, are available for a number of routine oil and gas activities. The LCZMP and its requirement to obtain coastal use permits may result in additional permitting requirements and associated project schedule constraints.

The Texas Coastal Coordination Act (“CCA”) provides for coordination among local and state authorities to protect coastal resources through regulating land use, water, and coastal development and establishes the Texas Coastal Management Program that applies in the nineteen counties that border the Gulf of Mexico and its tidal bays. The CCA provides for the review of state and federal agency rules and agency actions for consistency with the goals and policies of the Coastal Management Plan. This review may affect agency permitting and may add a further regulatory layer to some of our projects.

**OSHA.** 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 USEPA community right-to-know regulations under Title III of the federal Superfund Amendments and Reauthorization Act, and similar state statutes require us to organize and/or disclose information about hazardous materials used or produced in our operations. Certain of this information must be provided to employees, state and local governmental authorities and local citizens.

Management believes that we are in substantial compliance with current applicable environmental laws and regulations described above and that continued compliance with existing requirements will not have a material adverse impact on us.

## Corporate Offices

Our headquarters are located in Lafayette, Louisiana, in approximately 46,600 square feet of leased space, with an exploration office in The Woodlands, Texas in approximately 13,100 square feet of leased space. We also maintain owned or leased field offices in the areas of the major fields in which we operate properties or have a significant interest. Replacement of any of our leased offices would not result in material expenditures by us as alternative locations to our leased space are anticipated to be readily available.

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### Employees

We had 64 full-time employees as of February 13, 2017. In addition to our full time employees, we utilize the services of independent contractors to perform certain functions. We believe that our relationships with our employees are satisfactory. None of our employees are covered by a collective bargaining agreement.

### Available Information

We make available free of charge, or through the “Investors—SEC Documents” section of our website at [www.petroquest.com](http://www.petroquest.com), access to our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after such material is filed or furnished to the Securities and Exchange Commission. Our Code of Business Conduct and Ethics, our Corporate Governance Guidelines and the charters of our Audit, Compensation and Nominating and Corporate Governance Committees are also available through the “Investors—Corporate Governance” section of our website or in print to any stockholder who requests them.

### Item 1A. Risk Factors

#### Risks Related to Our Business, Industry and Strategy

***Oil and natural gas prices are volatile and an extended decline in the prices of oil and natural gas would likely have a material adverse effect our financial condition, liquidity, ability to meet our financial obligations and results of operations.***

Our future financial condition, revenues, results of operations, profitability and future growth, and the carrying value of our oil and natural gas properties depend primarily on the prices we receive for our oil and natural gas production. Our ability to maintain or increase our borrowing capacity and to obtain additional capital on attractive terms also substantially depends upon oil and natural gas prices. Historically, the markets for oil and natural gas have been volatile and oil prices have been significantly depressed since the end of 2014 as demonstrated by the SEC pricing for the value of crude oil and natural gas, which had decreased significantly as of December 31, 2016 as compared to December 31, 2014. For example, the SEC pricing at December 31, 2016 for crude oil (WTI Cushing) and natural gas (Henry Hub) was \$42.75 per Bbl and \$2.49 per MMBtu, respectively, as compared to \$94.99 per Bbl to a low of \$4.35 per MMBtu for crude oil and natural gas, respectively, at December 31, 2014. These markets will likely continue to be volatile in the future. The prices we will receive for our production, and the levels of our production, will depend on numerous factors beyond our control.

These factors include:

- relatively minor changes in the supply of or the demand for oil and natural gas;
- the condition of the United States and worldwide economies;
- market uncertainty;
- the level of consumer product demand;
- weather conditions in the United States, such as hurricanes;
- the actions of the Organization of Petroleum Exporting Countries;
- domestic and foreign governmental regulation and taxes, including price controls adopted by the FERC;
- political conditions or hostilities in oil and natural gas producing regions, including the Middle East and South America;
- the price and level of foreign imports of oil and natural gas; and
- the price and availability of alternate fuel sources.

We cannot predict future oil and natural gas prices and such prices may decline further. An extended decline in oil and natural gas prices has, and may continue to, adversely affect our financial condition, liquidity, ability to meet our financial obligations and results of operations. Lower prices have reduced and may further reduce the amount of oil and natural gas that we can produce economically and has required and will likely require us to record additional ceiling test write-downs and may cause our estimated

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proved reserves at December 31, 2017 to decline compared to our estimated proved reserves at December 31, 2016. Substantially all of our oil and natural gas sales are made in the spot market or pursuant to contracts based on spot market prices.

Our sales are not made pursuant to long-term fixed price contracts. To attempt to reduce our price risk, we periodically enter into hedging transactions with respect to a portion of our expected future production. We cannot assure you that we can enter into effective hedging transactions in the future or that such transactions will reduce the risk or minimize the effect of any decline in oil or natural gas prices. Any substantial or extended decline in the prices of or demand for oil or natural gas would have a material adverse effect on our financial condition, liquidity, ability to meet our financial obligations and results of operations.

***Our outstanding indebtedness may adversely affect our cash flow and our ability to operate our business, remain in compliance with debt covenants and make payments on our debt.***

The aggregate principal amount of our outstanding indebtedness, net of cash on hand, as of December 31, 2016 was \$265.3 million. We currently have \$40 million of additional availability under the Multidraw Term Loan Agreement, subject to compliance with the covenants contained therein. We may also incur additional indebtedness in the future. Our high level of debt could have important consequences for you, including the following:

- it may be more difficult for us to satisfy our obligations with respect to our outstanding indebtedness, including our 2017 Notes, 2021 Notes, 2021 PIK Notes and amounts borrowed under the Multidraw Term Loan Agreement, and any failure to comply with the obligations of any of our debt agreements, including financial and other restrictive covenants, could result in an event of default under the agreements governing such indebtedness;
- the covenants contained in our debt agreements limit our ability to borrow money in the future for acquisitions, capital expenditures or to meet our operating expenses or other general corporate obligations and may limit our flexibility in operating our business;
- we will need to use a substantial portion of our cash flows to pay interest on our debt of approximately \$5.9 million per year for interest on our 2017 Notes, 2021 Notes and 2021 PIK Notes alone (assuming we elect our PIK interest option with respect to the first three semi-annual interest payments on the 2021 PIK Notes (the "PIK Interest Option")), and to pay quarterly dividends (which we suspended beginning with the dividend payment due in April 2016), if permissible under the terms of our debt agreements and declared by our Board of Directors, on our 6.875% Series B Cumulative Convertible Perpetual Preferred Stock (the "Series B Preferred Stock") of approximately \$5.1 million per year, which will reduce the amount of money we have for operations, capital expenditures, expansion, acquisitions or general corporate or other business activities;
- we may have a higher level of debt than some of our competitors, which may put us at a competitive disadvantage;
- we may be more vulnerable to economic downturns and adverse developments in our industry or the economy in general, especially extended or further declines in oil and natural gas prices; and
- our debt level could limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate.

Our ability to meet our expenses and debt obligations will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. We will not be able to control many of these factors, such as economic conditions and governmental regulation. We cannot be certain that our cash flow from operations will be sufficient to allow us to pay the principal and interest on our debt, including our 2017 Notes, 2021 Notes, 2021 PIK Notes and amounts borrowed under the Multidraw Term Loan Agreement, and meet our other obligations. If we do not have enough cash to service our debt, we may be required to refinance all or part of our existing debt, including our 2017 Notes, 2021 Notes, 2021 PIK Notes and the Multidraw Term Loan Agreement, sell assets, borrow more money or raise equity. We may not be able to refinance our debt, sell assets, borrow more money or raise equity on terms acceptable to us, if at all.

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***To service our indebtedness, we will require a significant amount of cash. Our ability to generate cash depends on many factors beyond our control, and any failure to meet our debt obligations could harm our business, financial condition and results of operations.***

Our ability to make payments on and to refinance our indebtedness, including our 2017 Notes, 2021 Notes, 2021 PIK Notes and amounts borrowed under the Multidraw Term Loan Agreement, and to fund planned capital expenditures will depend on our ability to generate sufficient cash flow from operations in the future. To a certain extent, this is subject to general economic, financial, competitive, legislative and regulatory conditions and other factors that are beyond our control, including the prices that we receive for our oil and natural gas production.

We cannot assure you that our business will generate sufficient cash flow from operations or that future borrowings will be available to us under the Multidraw Term Loan Agreement in an amount sufficient to enable us to pay principal and interest on our indebtedness, including our 2017 Notes, 2021 Notes and 2021 PIK Notes, or to fund our other liquidity needs. If our cash flow and capital resources are insufficient to fund our debt obligations, we may be forced to reduce our planned capital expenditures, sell assets, seek additional equity or debt capital or restructure our debt. We cannot assure you that any of these remedies could, if necessary, be affected on commercially reasonable terms, or at all. In addition, any failure to make scheduled payments of interest and principal on our outstanding indebtedness would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness on acceptable terms. Our cash flow and capital resources may be insufficient for payment of interest on and principal of our debt in the future, including payments on our 2017 Notes, 2021 Notes, 2021 PIK Notes and amounts borrowed under the Multidraw Term Loan Agreement, and any such alternative measures may be unsuccessful or may not permit us to meet scheduled debt service obligations, which could cause us to default on our obligations and could impair our liquidity.

***We may not be able to obtain adequate financing when the need arises to execute our long-term operating strategy.***

Our ability to execute our long-term operating strategy is highly dependent on having access to capital when the need arises. We historically have addressed our long-term liquidity needs through bank credit facilities, second lien term credit facilities, issuances of equity and debt securities, sales of assets, joint ventures and cash provided by operating activities. We will examine the following alternative sources of long-term capital as dictated by current economic conditions:

- borrowings from banks or other lenders;
- the sale of certain assets;
- the issuance of debt securities;
- the sale of common stock, preferred stock or other equity securities;
- joint venture financing; and
- production payments.

The availability of these sources of capital when the need arises will depend upon a number of factors, some of which are beyond our control. These factors include general economic and financial market conditions, oil and natural gas prices, our credit ratings, interest rates, market perceptions of us or the oil and gas industry, our market value and our operating performance. We may be unable to execute our long-term operating strategy if we cannot obtain capital from these sources when the need arises.

***Borrowings under the Multidraw Term Loan Agreement are subject to our compliance with a significant financial ratio.***

Under the terms of the Multidraw Term Loan Agreement, our ability to borrow is based on our maintaining a ratio of (i) the present value, discounted at 10% per annum, of the estimated future net revenues in respect of our oil and gas properties, before any state, federal, foreign or other income taxes, attributable to proved developed reserves, using three-year strip prices in effect at the end of each calendar quarter, including swap agreements in place at the end of each quarter, to (ii) the sum of the outstanding term loans thereunder and the then outstanding commitments to provide term loans, that shall not be less than (a) 1.7 to 1.0 as measured on December 31, 2016, and March 31, 2017, and (b) 2.0 to 1.0 as measured on June 30, 2017, and the last day of each calendar quarter thereafter. We may not be able to comply with this restrictive financial ratio in the future and, as a result, our ability to borrow money under the Multidraw Term Loan Agreement could be limited, in which case we would need to find other sources of liquidity including, but not limited to, negotiated renewals of our borrowings, arranging new financing or selling a portion of our assets.

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***Restrictive debt covenants could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.***

The Multidraw Term Loan Agreement and the indentures governing our 2021 Notes and 2021 PIK Notes contain a number of significant covenants that, among other things, restrict or limit our ability to:

- pay dividends or distributions on our capital stock or issue preferred stock;
- repurchase, redeem or retire our capital stock or subordinated debt;
- make certain loans and investments;
- place restrictions on the ability of subsidiaries to make distributions;
- sell assets, including the capital stock of subsidiaries;
- enter into certain transactions with affiliates;
- create or assume certain liens on our assets;
- enter into sale and leaseback transactions;
- merge or enter into other business combination transactions;
- enter into transactions that would result in a change of control of us; or
- engage in other corporate activities.

Also, the Multidraw Term Loan Agreement requires us to maintain compliance with specified financial ratios and satisfy certain financial condition tests. Our ability to comply with these ratios and financial condition tests may be affected by events beyond our control, and we cannot assure you that we will meet these ratios and financial condition tests.

Further, these financial ratio restrictions and financial condition tests could limit our ability to obtain future financings, make needed capital expenditures, withstand a future downturn in our business or the economy in general or otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under the Multidraw Term Loan Agreement and the indentures governing our 2021 Notes and 2021 PIK Notes impose on us.

A breach of any of these covenants or our inability to comply with the required financial ratios or financial condition tests could result in a default under the Multidraw Term Loan Agreement, the 2021 Notes and the 2021 PIK Notes. A default, if not cured or waived, could result in all indebtedness outstanding under the Multidraw Term Loan Agreement, the 2021 Notes and the 2021 PIK Notes to become immediately due and payable. If that should occur, we may not be able to pay all such debt or borrow sufficient funds to refinance it. Even if new financing were then available, it may not be on terms that are acceptable to us. If we were unable to repay those amounts, the lenders could accelerate the maturity of the debt or proceed against any collateral granted to them to secure such defaulted debt.

***We may be able to incur substantially more debt, which could exacerbate the risks associated with our indebtedness.***

The PIK Interest Option of the 2021 PIK Notes will increase the aggregate amount of debt that must be repaid at maturity or otherwise. In addition, we and our subsidiaries may be able to incur substantial additional indebtedness in the future. Although covenants under the Multidraw Term Loan Agreement and the indentures governing our 2021 Notes and 2021 PIK Notes will limit our ability to incur additional indebtedness, these restrictions are subject to a number of qualifications and exceptions, and indebtedness incurred in compliance with these restrictions could be significant.

If new debt is added to our current debt levels, the related risks that we and our subsidiaries now face could intensify. Any of these risks could result in a material adverse effect on our business, financial condition, results of operations, business prospects and ability to satisfy our obligations under our outstanding indebtedness.

***A financial downturn or negative credit market conditions may have lasting effects on our liquidity, business and financial condition that we cannot predict.***

Liquidity is essential to our business. Our liquidity could be substantially negatively affected by an inability to obtain capital in the long-term or short-term debt capital markets or equity capital markets or an inability to access bank or other financing. A prolonged credit crisis or turmoil in the domestic or global financial systems could materially affect our liquidity, business and financial condition. These conditions have adversely impacted financial markets previously and created substantial volatility and

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uncertainty, and could do so again, with the related negative impact on global economic activity and the financial markets. Negative credit market conditions could materially affect our liquidity and may inhibit our lender from fully funding our Multidraw Term Loan Agreement or cause our lender to make the terms of our Multidraw Term Loan Agreement costlier and more restrictive. A weak economic environment could also adversely affect the collectability of our trade receivables or performance by our suppliers and cause our commodity derivative arrangements to be ineffective if our counterparties are unable to perform their obligations or seek bankruptcy protection. Additionally, negative economic conditions could lead to reduced demand for oil, natural gas and NGLs or lower prices for oil, natural gas and NGLs, which could have a negative impact on our revenues.

***Our hedging program may limit potential gains from increases in commodity prices or may result in losses or may be inadequate to protect us against continuing and prolonged declines in commodity prices.***

We enter into hedging arrangements from time to time to reduce our exposure to fluctuations in oil and natural gas prices and to achieve more predictable cash flow. Our hedges at December 31, 2016 and as of the date of this report are in the form of swaps placed with Shell Trading Risk Management LLC. We cannot assure you that this or future counterparties will not become credit risks in the future. Hedging arrangements expose us to risks in some circumstances, including situations when the counterparty to the hedging contract defaults on the contractual obligations or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received. These hedging arrangements may also limit the benefit we could receive from increases in the market or spot prices for oil and natural gas.

For the year ended December 31, 2016, our total oil and gas sales included additions related to the settlement of gas hedges of \$1.8 million, which in total represented 3% of our total oil and gas sales for the year. We cannot assure you that the hedging transactions we have entered into, or will enter into, will adequately protect us from fluctuations in oil and natural gas prices. In addition, as of the date of this report, we had approximately 11.0 Bcf of gas volumes hedged for 2017 and 2.7 Bcf of gas volumes hedged for 2018. These hedges may be inadequate to protect us from continuing and prolonged declines in oil and natural gas prices. To the extent that oil and natural gas prices remain at current levels or decline further, we will not be able to hedge future production at the same pricing level as our current hedges and our results of operations and financial condition would be negatively impacted.

***We may be required to post additional collateral to satisfy the collateral requirements related to the surety bonds that secure our offshore decommissioning obligations or to increase the amount of surety bonds or other security required pursuant to updated BOEM financial assurance and risk management requirements.***

To cover the costs for various obligations of lessees on the OCS, including costs for such decommissioning obligations as the plugging of wells, the removal of platforms and other facilities, the decommissioning of pipelines and the clearing of the seafloor of obstructions typically performed at the end of production, the BOEM generally requires that the lessees post substantial bonds or other acceptable financial assurances that such obligations will be met. Failure to post the requisite bonds or otherwise satisfy the BOEM's security requirements could have a material adverse effect on our ability to operate in the U.S. Gulf of Mexico.

Because we are not exempt from the BOEM's supplemental bonding requirements, we engage surety companies to post the requisite bonds. Pursuant to the terms of our surety agreements, we may be required to post collateral at the surety companies' discretion. Two of our surety companies requested collateral be posted to support certain of the bonds issued on our behalf. To date, we have provided cash deposits totaling \$6.2 million to satisfy these requests. The surety companies may request additional collateral which could have a material adverse effect on our liquidity position. If we fail to satisfy the request for collateral, we may be in default under our agreements with the surety companies, which could cause a cross-default under the indentures governing the 2021 Notes and the 2021 PIK Notes and our Multidraw Term Loan Agreement.

In addition, on July 14, 2016, the BOEM issued a notice to lessees ("NTL") No. 2016-N01 effective September 12, 2016 to clarify the procedures and criteria that the BOEM will use to determine if and when additional security is required for OCS leases. This notice may result in an increase to the amount of surety bonds or other security required to be posted by us pursuant to these updated BOEM financial assurance and risk management requirements. On January 6, 2017, the BOEM announced that it was extending the implementation timeline for NTL No. 2016-N01 by an additional six months as to leases, rights-of-way and rights of use and easement for which there are co-lessees and/or predecessors in interest, except in circumstances in which BOEM determines there is a substantial risk of nonperformance of the interest holder's decommissioning liabilities. All of our decommissioning liabilities as of the date hereof have co-lessees and/or predecessors in interest and are expected to be included in this extended implementation timeline.

We can provide no assurance that we can continue to obtain bonds or other surety in all cases given these new expenses and updated BOEM requirements or that we will have sufficient liquidity to support such supplemental bonding requirements, and if we are unable to obtain the additional required bonds, assurances or the increased amount of required collateral as requested, the BOEM may require any or all of our operations on federal leases to be suspended or canceled or otherwise impose monetary

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penalties, and any one or more of such actions could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity.

***Our future success depends upon our ability to find, develop, produce and acquire additional oil and natural gas reserves that are economically recoverable.***

As is generally the case in the Gulf of Mexico and Gulf Coast Basin where approximately 54% of our current production is located, many of our producing properties are characterized by a high initial production rate, followed by a steep decline in production. In order to maintain or increase our reserves, we must constantly locate and develop or acquire new oil and natural gas reserves to replace those being depleted by production. We must do this even during periods of low oil and natural gas prices when it is difficult to raise the capital necessary to finance our exploration, development and acquisition activities. Without successful exploration, development or acquisition activities, our reserves and revenues will decline rapidly. We may not be able to find and develop or acquire additional reserves at an acceptable cost or have access to necessary financing for these activities, either of which would have a material adverse effect on our financial condition.

***Approximately 54% of our production is exposed to the additional risk of severe weather, including hurricanes and tropical storms, as well as flooding, coastal erosion and sea level rise.***

At December 31, 2016, approximately 54% of our production and approximately 28% of our estimated proved reserves are located in the Gulf of Mexico and along the Gulf Coast Basin. Operations in this area are subject to severe weather, including hurricanes and tropical storms, as well as flooding, coastal erosion and sea level rise. Some of these adverse conditions can be severe enough to cause substantial damage to facilities and possibly interrupt production. For example, certain of our Gulf Coast Basin properties have experienced damages and production downtime as a result of storms including Hurricanes Katrina and Rita, and more recently Hurricanes Gustav and Ike. In addition, according to certain scientific studies, emissions of carbon dioxide, methane, nitrous oxide and other gases commonly known as greenhouse gases may be contributing to global warming of the earth's atmosphere and to global climate change, which may exacerbate the severity of these adverse conditions. As a result, such conditions may pose increased climate-related risks to our assets and operations.

In accordance with customary industry practices, we maintain insurance against some, but not all, of these risks; however, losses could occur for uninsured risks or in amounts in excess of existing insurance coverage. We cannot assure you that we will be able to maintain adequate insurance in the future at rates we consider reasonable or that any particular types of coverage will be available. An event that is not fully covered by insurance could have a material adverse effect on our financial position and results of operations.

***SEC rules could limit our ability to book additional proved undeveloped reserves or require us to write down our proved undeveloped reserves.***

SEC rules require that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This requirement may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program. Moreover, we may be required to write down our proved undeveloped reserves if we do not develop those reserves within the required five-year time frame.

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

Although the estimates of our oil and natural gas reserves and future net cash flows attributable to those reserves were prepared by Ryder Scott Company, L.P., our independent petroleum and geological engineers, we are ultimately responsible for the disclosure of those estimates. Reserve engineering is a complex and subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and natural 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 wells;
- the assumed effects of regulations by governmental agencies;
- assumptions concerning future oil and natural gas prices; and
- assumptions concerning future operating costs, severance and excise taxes, development costs and work-over and remedial costs.

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Because all reserve 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 and natural gas that are ultimately recovered;
- the production and operating costs incurred;
- the amount and timing of future development expenditures; and
- future oil and natural gas sales prices.

Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same available data. Historically, the difference between our actual production and the production estimated in a prior year's reserve report has not been material. Our 2016 production, excluding the impact from successful exploration wells which are not included in the prior year reserve report, was approximately 18% lower than amounts projected in our 2015 reserve report as a result of the divestiture of the remainder of our Oklahoma assets. We cannot assure you that these differences will not be material in the future.

Approximately 41% of our estimated proved reserves at December 31, 2016 are undeveloped and 21% were developed, non-producing. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we will make significant capital expenditures to develop and produce our reserves. Although we have prepared estimates of our oil and natural gas reserves and the costs associated with these reserves in accordance with industry standards, we cannot assure you that the estimated costs are accurate, that the development will occur as scheduled or that the actual results will be as estimated. In addition, the recovery of certain developed non-producing reserves (primarily in the Gulf of Mexico) is generally subject to the approval of development plans and related activities by applicable state and/or federal agencies. Statutes and regulations may affect both the timing and quantity of recovery of estimated reserves. Such statutes and regulations, and their enforcement, have changed in the past and may change in the future, and may result in upward or downward revisions to current estimated proved reserves.

You should not assume that the standardized measure of discounted cash flows is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, the standardized measure of discounted cash flows from proved reserves at December 31, 2016 are based on twelve-month, first day of month, average prices and costs as of the date of the estimate. These prices and costs will change and may be materially higher or lower than the prices and costs as of the date of the estimate. Any changes in consumption by oil and natural gas purchasers or in governmental regulations or taxation may also affect actual future net cash flows. The actual timing of development activities, including related production and expenses, will affect the timing of future net cash flows and any differences between estimated development timing and actual could have a material effect on standardized measure. In addition, the 10% discount factor we use when calculating standardized measure of discounted cash flows for reporting requirements in compliance with accounting requirements is not necessarily the most appropriate discount factor. The effective interest rate at various times and the risks associated with our operations or the oil and natural gas industry in general will affect the accuracy of the 10% discount factor.

***We may be unable to successfully identify, execute or effectively integrate future acquisitions, which may negatively affect our results of operations.***

Acquisitions of oil and gas businesses and properties have been an important element of our business, and we will continue to pursue acquisitions in the future. In the last several years, we have pursued and consummated acquisitions that have provided us opportunities to grow our production and reserves. Although we regularly engage in discussions with, and submit proposals to, acquisition candidates, suitable acquisitions may not be available in the future on reasonable terms. If we do identify an appropriate acquisition candidate, we may be unable to successfully negotiate the terms of an acquisition, finance the acquisition or, if the acquisition occurs, effectively integrate the acquired business into our existing business. Negotiations of potential acquisitions and the integration of acquired business operations may require a disproportionate amount of management's attention and our resources. Even if we complete additional acquisitions, continued acquisition financing may not be available or available on reasonable terms, any new businesses may not generate revenues comparable to our existing business, the anticipated cost efficiencies or synergies may not be realized and these businesses may not be integrated successfully or operated profitably. The success of any acquisition will depend on a number of factors, including the ability to estimate accurately the recoverable volumes of reserves, rates of future production and future net revenues attainable from the reserves and to assess possible environmental liabilities. Our inability to successfully identify, execute or effectively integrate future acquisitions may negatively affect our results of operations.

Even though we perform due diligence reviews (including a review of title and other records) of the major properties we seek to acquire that we believe is consistent with industry practices, these reviews are inherently incomplete. It is generally not feasible for us to perform an in-depth review of every individual property and all records involved in each acquisition. However,



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even an in-depth review of records and properties may not necessarily reveal existing or potential problems or permit us to become familiar enough with the properties to assess fully their deficiencies and potential. Even when problems are identified, we may assume certain environmental and other risks and liabilities in connection with the acquired businesses and properties. The discovery of any material liabilities associated with our acquisitions could harm our results of operations.

In addition, acquisitions of businesses may require additional debt or equity financing, resulting in additional leverage or dilution of ownership. Our Multidraw Term Loan Agreement and the indentures governing our 2021 Notes and 2021 PIK Notes contain certain covenants that limit, or which may have the effect of limiting, among other things acquisitions, capital expenditures, the sale of assets and the incurrence of additional indebtedness.

### ***The loss of key management or technical personnel could adversely affect our ability to operate.***

Our operations are dependent upon a diverse group of key senior management. In addition, we employ numerous other skilled technical personnel, including geologists, geophysicists and engineers that are essential to our operations. We cannot assure you that such individuals will remain with us for the immediate or foreseeable future. The unexpected loss of the services of one or more of any of these key management or technical personnel could have an adverse effect on our operations.

### ***Losses and liabilities from uninsured or underinsured drilling and operating activities could have a material adverse effect on our financial condition and operations.***

We maintain several types of insurance to cover our operations, including worker's compensation, maritime employer's liability and comprehensive general liability. Amounts over base coverages are provided by primary and excess umbrella liability policies. We also maintain operator's extra expense coverage, which covers the control of drilling or producing wells as well as redrilling expenses and pollution coverage for wells out of control.

We may not be able to maintain adequate insurance in the future at rates we consider reasonable, or we could experience losses that are not insured or that exceed the maximum limits under our insurance policies. If a significant event that is not fully insured or indemnified occurs, it could materially and adversely affect our financial condition and results of operations.

### ***Lower oil and natural gas prices may cause us to record ceiling test write-downs, which could negatively impact our results of operations.***

We use the full cost method of accounting to account for our oil and natural gas operations. Accordingly, we capitalize the cost to acquire, explore for and develop oil and natural gas properties. Under full cost accounting rules, the net capitalized costs of oil and natural gas properties may not exceed a "full cost ceiling" which is based upon the present value of estimated future net cash flows from proved reserves, including the effect of hedges in place, discounted at 10%, plus the lower of cost or fair market value of unproved properties. If at the end of any fiscal period we determine that the net capitalized costs of oil and natural gas properties exceed the full cost ceiling, we must charge the amount of the excess to earnings in the period then ended. This is called a "ceiling test write-down." This charge does not impact cash flow from operating activities, but does reduce our net income and stockholders' equity. Once incurred, a write-down of oil and natural gas properties is not reversible at a later date.

We review the net capitalized costs of our properties quarterly, using a single price based on the twelve-month, first day of month, average price of oil and natural gas for the prior 12 months. We also assess investments in unevaluated properties periodically to determine whether impairment has occurred. The risk that we will be required to recognize further write downs of the carrying value of our oil and gas properties increases when oil and natural gas prices are low or volatile. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves or our unevaluated property values, or if estimated future development costs increase. As a result of the decline in commodity prices, we recognized ceiling test write-downs totaling \$40.3 million and \$266.6 million during the years ended December 31, 2016 and 2015, respectively. Utilizing current strip prices for oil and natural gas prices for the first quarter of 2017 and projecting the effect on the estimated future net cash flows from our estimated proved reserves as of March 31, 2017, we do not expect to recognize an additional ceiling test write-down in the first quarter of 2017.

### ***Factors beyond our control affect our ability to market oil and natural gas.***

The availability of markets and the volatility of product prices are beyond our control and represent a significant risk. The marketability of our production depends upon the availability and capacity of natural gas gathering systems, pipelines and processing facilities. The unavailability or lack of capacity of these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Our ability to market oil and natural gas also depends on other factors beyond our control. These factors include:

- the level of domestic production and imports of oil and natural gas;

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- the proximity of natural gas production to natural gas pipelines;
- the availability of pipeline capacity;
- the demand for oil and natural gas by utilities and other end users;
- the availability of alternate fuel sources;
- the effect of inclement weather, such as hurricanes;
- state and federal regulation of oil and natural gas marketing; and
- federal regulation of natural gas sold or transported in interstate commerce.

If these factors were to change dramatically, our ability to market oil and natural gas or obtain favorable prices for our oil and natural gas could be adversely affected.

### ***The explosion and sinking of the Deepwater Horizon drilling rig in the Gulf of Mexico in April 2010 and the resulting oil spill may significantly increase our risks, costs and delays.***

The explosion and sinking of the Deepwater Horizon drilling rig in the Gulf of Mexico in April 2010 and the resulting oil spill may significantly impact the risks we face. The Deepwater Horizon incident and resulting legislative, regulatory and enforcement changes, including increased tort liability, could increase our liability if any incidents occur on our offshore operations. We cannot predict the ultimate impact the Deepwater Horizon incident and resulting changes in regulation of offshore oil and natural gas operations will have on our business or operations.

In response to the spill, and during a moratorium on deepwater (below 500 feet) drilling activities implemented between May 30, 2010 and October 12, 2010, the BOEMRE issued a series of active NTLs, and adopted changes to its regulations to impose a variety of new measures intended to help prevent a similar disaster in the future.

Offshore operators, including those operating in deepwater, OCS waters and shallow waters, where we have substantial operations, must comply with strict new safety and operating requirements. For example, permit applications for drilling projects must meet new standards with respect to well design, casing and cementing, blowout preventers, safety certification, emergency response, and worker training. Operators in all offshore waters are also required to demonstrate the availability of adequate spill response and blowout containment resources. In addition, the BSEE imposed, for the first time, requirements that offshore operators maintain comprehensive safety and environmental programs. Such developments have the potential to increase our costs of doing business.

### ***Federal and state legislation and regulatory initiatives relating to oil and natural gas development and hydraulic fracturing could result in increased costs and additional operating restrictions or delays.***

Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to enhance oil and natural gas production. Hydraulic fracturing using fluids other than diesel is currently exempt from regulation under the federal Safe Drinking Water Act, but opponents of hydraulic fracturing have called for further study of the technique's environmental effects and, in some cases, further regulation of the technique under various federal and state authorities. A number of states, including Louisiana and Texas, have required operators or service companies to disclose chemical components in fluids used for hydraulic fracturing and some states have imposed bans or moratoria on new natural gas development or the use of hydraulic fracturing. Further regulation may include, among other things, additional permitting requirements, enhanced reporting obligations, and stricter standards for discharges and emissions associated with gas production, storage and transport. The future of such regulation is controversial and uncertain. Such requirements, if imposed, would be expected to increase the cost of natural gas production.

Recent seismic events have been observed in some areas (including Texas) where hydraulic fracturing has taken place. Some scientists believe the increased seismic activity may result from deep well fluid injection associated with use of hydraulic fracturing. Additional regulatory measures designed to minimize or avoid damage to geologic formations have been imposed in states, including Texas, to address such concerns.

Concerns regarding climate change have led the Congress, various states and environmental agencies to consider a number of initiatives to restrict or regulate emissions of greenhouse gases, such as carbon dioxide and methane. Stricter regulations of greenhouse gases could require us to incur costs to reduce emissions of greenhouse gases associated with our operations, or could adversely affect demand for the oil and natural gas we produce. In addition, climate change that results in physical effects such

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as increased frequency and severity of storms, floods and other climatic events, could disrupt our exploration and production operations and cause us to incur significant costs in preparing for and responding to those effects.

Although it is not possible at this time to predict any additional federal, state or local legislation or regulation regarding hydraulic fracturing, management of drilling fluids, stricter emission standards, well integrity requirements or climate change, federal or state restrictions imposed on oil and gas exploration and production activities in areas in which we conduct business could significantly increase our operating, capital and compliance costs as well as delay our ability to develop oil and natural gas reserves. In addition to increased regulation of our business, we may also experience an increase in litigation seeking damages as a result of heightened public concerns related to air quality, water quality, and other environmental impacts.

***The adoption of derivatives legislation by Congress, and implementation of that legislation by federal agencies, could have an adverse impact on our ability to mitigate risks associated with our business.***

On July 21, 2010, the President signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Reform Act”), which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The legislation required the Commodities Futures Trading Commission, (the “CFTC”), and the SEC to promulgate rules and regulations implementing the new legislation, which they have done since late 2010. The CFTC has introduced dozens of proposed rules coming out of the Dodd-Frank Reform Act, and has promulgated numerous final rules based on those proposals. The effect of the proposed rules and any additional regulations on our business is not yet entirely clear, but it is increasingly clear that the costs of derivatives-based hedging for commodities will likely increase for all market participants. Of particular concern, the Dodd-Frank Reform Act does not explicitly exempt end users from the requirements to post margin in connection with hedging activities. While several senators have indicated that it was not the intent of the Dodd-Frank Reform Act to require margin from end users, the exemption is not in the Dodd-Frank Reform Act. While rules proposed by the CFTC and federal banking regulators appear to allow for non-cash collateral and certain exemptions from margin for end users, the rules are not final and uncertainty remains. The full range of new Dodd-Frank Reform Act requirements to be enacted, to the extent applicable to us or our derivatives counterparties, may result in increased costs and cash collateral requirements for the types of derivative instruments we use to mitigate and otherwise manage our financial and commercial risks related to fluctuations in oil and natural gas prices. In addition, final rules were promulgated by the CFTC imposing federally-mandated position limits covering a wide range of derivatives positions, including non-exchange traded bilateral swaps related to commodities including oil and natural gas. These position limit rules were vacated by a Federal court in September 2012. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, their impact on us is uncertain at this time. If these position limits rules go into effect in the future, they are likely to increase regulatory monitoring and compliance costs for all market participants, even where a given trading entity is not in danger of breaching position limits. These and other regulatory developments stemming from the Dodd-Frank Reform Act, including stringent new reporting requirements for derivatives positions and detailed criteria that must be satisfied to continue to enter into uncleared swap transactions, could have a material impact on our derivatives trading and hedging activities in the form of increased transaction costs and compliance responsibilities. Any of the foregoing consequences could have a material adverse effect on our financial position, results of operations and cash flows.

***Proposed changes to U.S. tax laws, if adopted, could have an adverse effect on our business, financial condition, results of operations and cash flows.***

From time to time legislative proposals are made that would, if enacted, make significant changes to U.S. tax laws. These proposed changes have included, among others, eliminating the immediate deduction for intangible drilling and development costs, eliminating the deduction from income for domestic production activities relating to oil and natural gas exploration and development, repealing the percentage depletion allowance for oil and natural gas properties and extending the amortization period for certain geological and geophysical expenditures. Such proposed changes in the U.S. tax laws, if adopted, or other similar changes that reduce or eliminate deductions currently available with respect to oil and natural gas exploration and development, could adversely affect our business, financial condition, results of operations and cash flows.

***We face strong competition from larger oil and natural gas companies that may negatively affect our ability to carry on operations.***

We operate in the highly competitive areas of oil and natural gas exploration, development and production. Factors that affect our ability to compete successfully in the marketplace include:

- the availability of funds and information relating to a property;
- the standards established by us for the minimum projected return on investment; and

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- the transportation of natural gas.

Our competitors include major integrated oil companies, substantial independent energy companies, affiliates of major interstate and intrastate pipelines and national and local natural gas gatherers, many of which possess greater financial and other resources than we do. If we are unable to successfully compete against our competitors, our business, prospects, financial condition and results of operations may be adversely affected.

### ***Operating hazards may adversely affect our ability to conduct business.***

Our operations are subject to risks inherent in the oil and natural gas industry, such as:

- unexpected drilling conditions including blowouts, cratering and explosions;
- uncontrollable flows of oil, natural gas or well fluids;
- equipment failures, fires or accidents;
- pollution and other environmental risks; and
- shortages in experienced labor or shortages or delays in the delivery of equipment.

These risks could result in substantial losses to us from injury and loss of life, damage to and destruction of property and equipment, pollution and other environmental damage and suspension of operations. Our offshore operations are also subject to a variety of operating risks peculiar to the marine environment, such as hurricanes or other adverse weather conditions and more extensive governmental regulation. These regulations may, in certain circumstances, impose strict liability for pollution damage or result in the interruption or termination of operations.

### ***Environmental compliance costs and environmental liabilities could have a material adverse effect on our financial condition and operations.***

Our operations are subject to numerous federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may:

- require the acquisition of permits before drilling commences;
- restrict the types, quantities and concentration of various substances that can be released into the environment from drilling and production activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas;
- require remedial measures to mitigate pollution from former operations, such as plugging abandoned wells; and
- impose substantial liabilities for pollution resulting from our operations.

The trend toward stricter requirements and standards in environmental legislation and regulation is likely to continue. Our drilling plans may be delayed, modified or precluded as a result of new or modified environmental mandates, including those imposed to protect the American Burying Beetle and other endangered species that may be present in the vicinity of our operations. The enactment of stricter legislation or the adoption of stricter regulations could have a significant impact on our operating costs, as well as on the oil and natural gas industry in general.

Our operations could result in liability for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. We could also be liable for environmental damages caused by previous property owners. As a result, substantial liabilities to third parties or governmental entities may be incurred which could have a material adverse effect on our financial condition and results of operations. We maintain insurance coverage for our operations, including limited coverage for sudden and accidental environmental damages, but this insurance may not extend to the full potential liability that could be caused by sudden and accidental environmental damages nor continue to be available in the future, and if available, may not cover environmental damages that occur over time. Accordingly, we may be subject to liability or may lose the ability to continue exploration or production activities upon substantial portions of our properties if certain environmental damages occur.

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### ***We cannot control the activities on properties we do not operate and we are unable to ensure the proper operation and profitability of these non-operated properties.***

We do not operate all of the properties in which we have an interest. As a result, we have limited ability to exercise influence over, and control the risks associated with, the operation of these properties. The success and timing of drilling and development activities on our partially owned properties operated by others therefore will depend upon a number of factors outside of our control, including the operator's:

- timing and amount of capital expenditures;
- expertise and diligence in adequately performing operations and complying with applicable agreements;
- financial resources;
- inclusion of other participants in drilling wells; and
- use of technology.

As a result of any of the above or an operator's failure to act in ways that are in our best interest, our allocated production revenues and results of operations could be adversely affected.

### ***Ownership of working interests and overriding royalty interests in certain of our properties by certain of our officers and directors potentially creates conflicts of interest.***

Certain of our executive officers and directors or their respective affiliates are working interest owners or overriding royalty interest owners in certain properties. In their capacity as working interest owners, they are required to pay their proportionate share of all costs and are entitled to receive their proportionate share of revenues in the normal course of business. As overriding royalty interest owners they are entitled to receive their proportionate share of revenues in the normal course of business. There is a potential conflict of interest between us and such officers and directors with respect to the drilling of additional wells or other development operations with respect to these properties.

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

We are heavily dependent on our information systems and computer based programs, including our well operations information, seismic data, electronic data processing and accounting data. If any of such 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 and natural gas and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence could have a material adverse effect on our business.

### ***A terrorist attack or armed conflict could harm our business.***

Terrorist activities, anti-terrorist efforts and other armed conflicts involving the United States or other countries may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occur, the resulting political instability and societal disruption could reduce overall demand for oil and natural gas, potentially putting downward pressure on demand for our production and causing a reduction in our revenues. Oil and natural gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if infrastructure integral to our customers' operations is destroyed or damaged. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

### ***We are subject of putative class action lawsuits that may result in substantial expenditures and divert management's attention.***

We are the subject of two putative class actions lawsuits in Oklahoma with respect to the alleged failure to pay interest with respect to untimely royalty payments and with respect to the alleged underpayment or failure to pay royalties by various means. These lawsuits seek various remedies, including damages, injunctive relief and attorney's fees. For additional information on these lawsuits, see Part II - Item 1. Legal Proceedings in this Form 10-K.

Although we believe that the allegations in these lawsuits are without merit and intend to defend such litigation vigorously, litigation is subject to inherent uncertainties, and an adverse result in one of these lawsuits or other matters that may arise from time to time could have a material adverse effect on our business, results of operations and financial condition. Defending the lawsuits may be costly and, further, could require significant involvement of our senior management and may divert management's attention from our business and operations.

### Risks Relating to Our Outstanding Common Stock

#### ***Our stock price could be volatile, which could cause you to lose part or all of your investment.***

The stock market has from time to time experienced significant price and volume fluctuations that may be unrelated to the operating performance of particular companies. In particular, the market price of our common stock, like that of the securities of many other energy companies, has been and may continue to be highly volatile. During 2016, the sales price of our stock ranged from a low of \$1.32 per share (on January 11, 2016) to a high of \$4.51 per share (on November 30, 2016). Factors such as announcements concerning changes in prices of oil and natural gas, the success of our acquisition, exploration and development activities, the availability of capital, and economic and other external factors, as well as period-to-period fluctuations and financial results, may have a significant effect on the market price of our common stock.

From time to time, there has been limited trading volume in our common stock. In addition, there can be no assurance that there will continue to be a trading market or that any securities research analysts will continue to provide research coverage with respect to our common stock. It is possible that such factors will adversely affect the market for our common stock.

#### ***If we cannot meet the New York Stock Exchange's continuing listing requirements and rules, the New York Stock Exchange may delist our securities, which could negatively affect our company, the price of our securities and your ability to sell our securities.***

On December 8, 2015, we received a notice from NYSE Regulation, Inc. informing us that we were not in compliance with the continued listing standards set forth in 802.01C of the Listed Company Manual of the New York Stock Exchange (the "Listed Company Manual"), because the average closing price of the our common stock fell below \$1.00 per share for a period of over 30 consecutive trading days. On May 18, 2016, we effected a 1:4 reverse stock split (the "Reverse Split") to attempt to increase the per share trading price of our common stock in order to regain compliance with the NYSE's continued listing standards. On June 2, 2016, we received a notice from the New York Stock Exchange ("NYSE") that the Company has regained compliance with this continued listing standard.

On December 28, 2015, we received another notice from NYSE Regulation, Inc. informing us that we were not in compliance with the continued listing standards set forth in Section 802.01B of the Listed Company Manual because our average global market capitalization fell below \$50 million over a trailing consecutive 30 trading-day period and our last reported stockholders' equity was less than \$50 million. We developed and submitted a business plan to the NYSE demonstrating how, within the next eighteen months, we intended to regain compliance with the continued listing standards set forth in Section 802.01B of the Listed Company Manual. On March 21, 2016, we received notice from the NYSE that our business plan had been accepted, that we will be subject to quarterly monitoring for compliance with the business plan and that our common stock will continue to trade on the NYSE during the eighteen month period, subject to our compliance with other NYSE continued listing requirements. The NYSE may choose to shorten the usual compliance period if prior to the end of the eighteen month period our global market capitalization exceeds \$50 million for two consecutive quarters.

If our common stock ultimately were to be delisted for any reason, trading of our securities would thereafter be conducted in the over-the-counter market or on the National Association of Securities Dealers Inc.'s "electronic bulletin board." As a consequence, our stockholders would likely find it more difficult to dispose of, or to obtain accurate quotations as to the prices of our securities. Such a delisting could negatively impact us by (i) reducing the liquidity and market price of our common stock; (ii) reducing the number of investors willing to hold or acquire our common stock, which could negatively impact our ability to raise equity financing; (iii) limiting our ability to use a registration statement to offer and sell freely tradable securities, thereby preventing us from accessing the public capital markets; and (iv) impairing our ability to provide equity incentives to our employees.

#### ***The terms of our debt agreements currently restrict and Delaware law may restrict us from making cash payments with respect to our Series B Preferred Stock.***

Quarterly dividends and cash payments upon conversion or repurchase of our Series B Preferred Stock will be paid only if payment of such amounts is not prohibited by our debt agreements, such as the Multidraw Term Loan Agreement, and assets are legally available to pay such amounts. Quarterly dividends will only be paid if such dividends are declared by our board of directors. The board of directors is not obligated or required to declare quarterly dividends even if we have funds available for such purposes.

The terms of the Multidraw Term Loan Agreement currently restrict us from paying cash dividends on our Series B Preferred Stock. We previously suspended the cash dividend on our Series B Preferred Stock beginning with the dividend payment due on April 15, 2016. Under the terms of the Series B Preferred Stock, any unpaid dividends will accumulate. If we fail to pay six quarterly dividends on the Series B Preferred Stock, whether or not consecutive, holders of the Series B Preferred Stock, voting as a single class, will have the right to elect two additional directors to our board of directors until all accumulated and unpaid

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dividends on the Series B Preferred Stock are paid in full. We plan to periodically re-evaluate the dividend payment policy, subject to the terms of our Multidraw Term Loan Facility.

If in the future we are permitted to pay such cash dividends under the terms of our existing debt agreements, including the Multidraw Term Loan Agreement, and any debt agreements that we enter into in the future, we may continue to be limited in our ability to pay cash dividends on our Series B Preferred Stock and our ability to make any cash payment upon conversion or repurchase of our Series B Preferred Stock by the terms of such debt agreements. Furthermore, if we are in default under the Multidraw Term Loan Agreement or the indenture governing the 2021 Notes or the 2021 PIK Notes, we will not be permitted to pay any cash dividends on our Series B Preferred Stock or make any cash payment upon conversion or repurchase of our Series B Preferred Stock in the absence of a waiver of such default or an amendment or refinancing of such debt agreements.

Delaware law provides that we may pay dividends on our Series B Preferred Stock only to the extent that assets are legally available to pay such dividends. Cash payments we may make upon repurchase or conversion of our Series B Preferred Stock would be generally subject to the same restrictions under Delaware law. Legally available assets is defined as the amount of surplus. Our surplus is the amount by which the fair value of total assets exceeds the sum of:

- the fair value of our total liabilities, including our contingent liabilities; and
- the amount of our capital.

If there is no surplus, legally available assets will mean, in the case of a dividend, our net profits for the fiscal year in which the dividend payment occurs and/or the preceding fiscal year.

***Issuance of shares in connection with financing transactions or under stock incentive plans will dilute current stockholders.***

We have issued 1.5 million shares of Series B Preferred Stock, which are presently convertible into 1.3 million shares of our common stock. In addition, pursuant to our stock incentive plan, our management is authorized to grant stock awards to our employees, directors and consultants. You will incur dilution upon the conversion of the Series B Preferred Stock, the exercise of any outstanding stock awards or the grant of any restricted stock. In addition, if we raise additional funds by issuing additional common stock, or securities convertible into or exchangeable or exercisable for common stock, further dilution to our existing stockholders will result, and new investors could have rights superior to existing stockholders.

***The number of shares of our common stock eligible for future sale could adversely affect the market price of our stock.***

At December 31, 2016, we had reserved approximately 1.4 million shares of common stock for issuance under outstanding options and approximately 1.3 million shares issuable upon conversion of the Series B Preferred Stock. All of these shares of common stock are registered for sale or resale on currently effective registration statements. In addition, we recently issued approximately 7.8 million shares (4.6 million shares as adjusted for the Reverse Split) of common stock in connection with the 2016 debt exchanges that are eligible for future sale under Rule 144 of the Securities Act. We may issue additional restricted securities or register additional shares of common stock under the Securities Act in the future. The issuance of a significant number of shares of common stock upon the exercise of stock options, the granting of restricted stock or the conversion of the Series B Preferred Stock, or the availability for sale, or sale, of a substantial number of the shares of our common stock eligible for future sale under effective registration statements, under Rule 144 or otherwise, could adversely affect the market price of the common stock.

***Provisions in our certificate of incorporation and bylaws could delay or prevent a change in control of our company, even if that change would be beneficial to our stockholders.***

Certain provisions of our certificate of incorporation and bylaws may delay, discourage, prevent or render more difficult an attempt to obtain control of our company, whether through a tender offer, business combination, proxy contest or otherwise. These provisions include:

- the charter authorization of “blank check” preferred stock;
- a restriction on the ability of stockholders to call a special meeting and take actions by written consent; and
- provisions regulating the ability of our stockholders to nominate directors for election or to bring matters for action at annual meetings of our stockholders.

***We do not intend to pay dividends on our common stock and our ability to pay dividends on our common stock is restricted.***

We have not paid dividends on our common stock, in cash or otherwise, and intend to retain our cash flow from operations for the future operation and development of our business. We are currently restricted from paying dividends on our common stock

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by our Multidraw Term Loan Agreement, the indentures governing the 2021 Notes and 2021 PIK Notes and, in some circumstances, by the terms of our Series B Preferred Stock. Any future dividends also may be restricted by our then-existing debt agreements.

### Item 1B      **Unresolved Staff Comments**

None

### Item 3.      **Legal Proceedings**

The Company is involved in litigation relating to claims arising out of its operations in the normal course of business, including worker's compensation claims, tort claims and contractual disputes. Some of the existing known claims against us are covered by insurance subject to the limits of such policies and the payment of deductible amounts by us. Although we cannot predict the outcome of these proceedings with certainty, management believes that the ultimate disposition of all uninsured or unindemnified matters resulting from existing litigation will not have a material adverse effect on the Company's business or financial position.

On May 27, 2016, the Company was named as a defendant in a putative class action lawsuit filed on behalf of holders of the 2017 Notes in the U.S. District Court for the Southern District of New York. The lawsuit alleges that, as a result of the February 2016 debt exchange, the Company violated the Trust Indenture Act of 1939, the indenture governing the 2017 Notes and the implied covenant of good faith and fair dealing by benefiting itself and a minority of noteholders who are qualified institutional buyers ("QIBs"). According to the lawsuit, as a result of the February 2016 debt exchange in which only QIBs (and non-U.S. persons under Regulation S) were eligible to participate, the Company unjustly enriched itself at the expense of class members by reducing indebtedness, extending the maturity date of its long term debt and reducing the value of the 2017 Notes. The lawsuit seeks damages and attorney's fees, in addition to declaratory relief that the debt exchange and the liens created for the benefit of the 2021 Notes are null and void and that the debt exchange resulted in a default under the indenture for the 2017 Notes. In August 2016, the lawsuit was transferred to the U.S. District Court for the Western District of Louisiana. On January 25, 2017, the lawsuit was voluntarily dismissed.

On October 11, 2016, the Company's subsidiary, PetroQuest Energy, L.L.C. ("PQ LLC"), and another exploration and production company were named as defendants in a putative class action lawsuit filed on behalf of royalty owners in the state district court in Hughes County, Oklahoma. The lawsuit alleges that PQ LLC and the other defendant failed to pay interest with respect to untimely royalty payments. The lawsuit seeks actual and punitive damages, an accounting, disgorgement, injunctive relief and attorney's fees. On November 28, 2016, the Company removed the lawsuit to the U.S. District Court for the Eastern District of Oklahoma.

On October 25, 2016, PQ LLC and another exploration and production company were named as defendants in a putative class action lawsuit filed on behalf of royalty owners in the U.S. District Court for the Eastern District of Oklahoma. The lawsuit alleges that PQ LLC and the other defendant underpaid royalties or did not pay royalties by various means. The lawsuit seeks actual, compensatory and punitive damages, and attorney's fees.

We continue to vigorously defend against each of the pending claims. At this time we are unable to express an opinion with respect to the likelihood of an unfavorable outcome or provide an estimate of potential losses, if any.

### Item 4.      **Mine Safety Disclosures**

Not applicable.

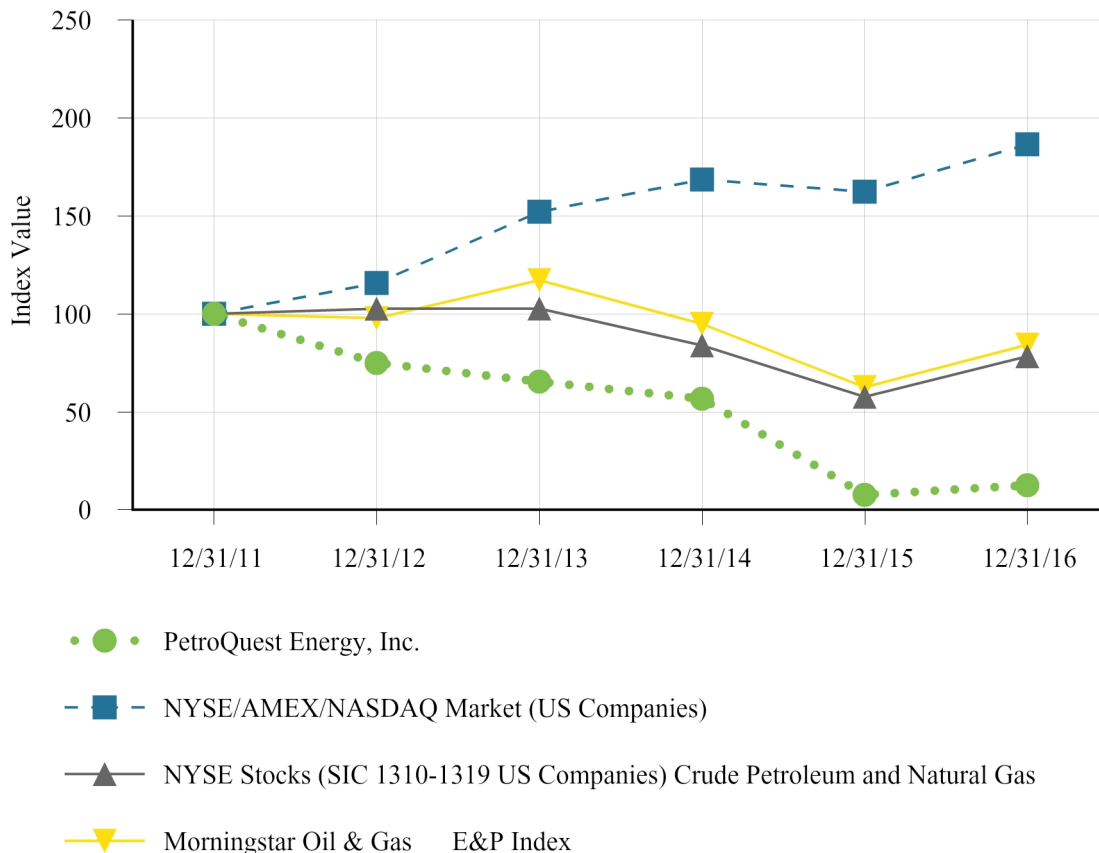


PART II

**Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities**

The following graph illustrates the yearly percentage change in the cumulative stockholder return on our common stock, compared with the cumulative total return on the NYSE/AMEX Stock Market (U.S. Companies) Index, the NYSE Stocks—Crude Petroleum and Natural Gas Index and the Morningstar Oil and Gas E&P Index, for the five years ended December 31, 2016.

**Comparison of 5 Year Cumulative Total Return  
Assumes Initial Investment of \$100  
December 31, 2016**



	PetroQuest Energy, Inc.	NYSE/AMEX/NASDAQ Market (US Companies)	NYSE Stocks (SIC 1310-1319 US Companies) Crude Petroleum and Natural Gas	Morningstar Oil & Gas E&P Index
12/31/2011	\$100.00	\$100.00	\$100.00	\$100.00
12/31/2012	75.00	115.63	102.61	97.82
12/31/2013	65.45	152.02	102.74	117.23
12/31/2014	56.67	168.47	83.89	94.82
12/31/2015	7.58	162.20	57.62	62.59
12/31/2016	12.54	186.49	78.36	84.26

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### Market Price of and Dividends on Common Stock

Our common stock trades on the New York Stock Exchange under the symbol “PQ.” The following table lists high and low sales prices per share for the periods indicated. The prices per share of our common stock prior to the 1 for 4 reverse stock split effective for trading purposes on May 19, 2016 have been adjusted to reflect this stock split on a retroactive basis and may not represent actual transactions.

<u>2015</u>		<u>High</u>	<u>Low</u>
1st Quarter	\$	15.32	\$ 7.80
2nd Quarter		10.96	6.80
3rd Quarter		7.96	4.20
4th Quarter		6.04	1.24
<u>2016</u>			
1st Quarter	\$	2.96	\$ 1.32
2nd Quarter		3.79	1.77
3rd Quarter		3.64	1.71
4th Quarter		4.51	2.83

As of March 2, 2017, there were 165 common stockholders of record.

We have never paid a dividend on our common stock, cash or otherwise, and intend to retain our cash flow from operations for the future operation and development of our business. In addition, under our Multidraw Term Loan Agreement and the indentures governing the 2021 Notes and 2021 PIK Notes, and, in some circumstances, the terms of our Series B Preferred Stock, we are restricted from paying cash dividends on our common stock. The payment of future dividends, if any, will be determined by our Board of Directors in light of conditions then existing, including our earnings, financial condition, capital requirements, restrictions in financing agreements, business conditions and other factors. See Item 1A. “Risk Factors – Risks Relating to our Outstanding Common Stock – We do not intend to pay dividends on our common stock and our ability to pay dividends on our common stock is restricted.”

The following table sets forth certain information with respect to repurchases of our common stock during the quarter ended December 31, 2016.

	Total Number of Shares Purchased (1)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plan or Program	Maximum Number (or Approximate Dollar Value) of Shares that May be Purchased Under the Plans or Programs
October 1—October 31, 2016	1,242	\$ 4.06	—	—
November 1—November 30, 2016	36,274	\$ 3.20	—	—
December 1—December 31, 2016	—	\$ —	—	—

(1) All shares repurchased were surrendered by employees to pay tax withholding upon the vesting of restricted stock awards.

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### Item 6. Selected Financial Data

The following table sets forth, as of the dates and for the periods indicated, selected financial information for the Company. The financial information for each of the five years in the period ended December 31, 2016 has been derived from the audited Consolidated Financial Statements of the Company for such periods. The information should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the Consolidated Financial Statements and notes thereto. The following information is not necessarily indicative of future results of the Company. All amounts are stated in U.S. dollars unless otherwise indicated.

	Year Ended December 31,				
	2016 (1)	2015 (2)	2014	2013	2012 (3)
	(in thousands except per share and per Mcfe data)				
Average sales price per Mcfe	\$ 2.84	\$ 3.39	\$ 5.19	\$ 4.80	\$ 4.17
Revenues	66,667	115,969	225,021	182,804	141,433
Net income (loss) available to common stockholders	(96,245)	(299,929)	26,051	8,943	(137,218)
Net income (loss) available to common stockholders per share:					
Basic	(5.24)	(18.45)	1.57	0.56	(8.80)
Diluted	(5.24)	(18.45)	1.57	0.56	(8.80)
Oil and gas properties, net	89,062	165,952	683,812	581,242	333,946
Total assets	144,860	379,319	786,108	660,018	430,647
Long-term debt, including current portion	293,645	347,008	420,213	417,828	147,244
Stockholders' equity	(251,095)	(163,067)	136,909	99,095	87,591

- (1) The year ended December 31, 2016 includes a pre-tax ceiling test write-down of \$40.3 million.
- (2) The year ended December 31, 2015 includes a pre-tax ceiling test write-down of \$266.6 million.
- (3) The year ended December 31, 2012 includes a pre-tax ceiling test write-down of \$137.1 million.

### Item 7.

## MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

### Overview

PetroQuest Energy, Inc. is an independent oil and gas company incorporated in the State of Delaware with primary operations in Texas, Louisiana and the shallow waters of the Gulf of Mexico. We seek to grow our production, proved reserves, cash flow and earnings at low finding and development costs through a balanced mix of exploration, development and acquisition activities. From the commencement of our operations through 2002, we were focused exclusively in the Gulf Coast Basin with onshore properties principally in southern Louisiana and offshore properties in the shallow waters of the Gulf of Mexico shelf. During 2003, we began the implementation of our strategic goal of diversifying our reserves and production into longer life and lower risk onshore properties with our acquisition of the Carthage Field in East Texas. As part of the strategic shift to diversify our asset portfolio and lower our geographic and geologic risk profile, we refocused our opportunity selection processes to reduce our average working interest in higher risk projects, shift capital to higher probability of success onshore wells and mitigate the risks associated with individual wells by expanding our drilling program across multiple basins. From 2005 through 2015, we were actively acquiring acreage and drilling wells primarily in the Woodford Shale play in Oklahoma. We divested all of our acreage and producing wells in Oklahoma in three transactions that closed in June 2015, April 2016 and October 2016 ("the Oklahoma Divestitures"). See Note 2 - Acquisitions and Divestitures.

Our liquidity position has been negatively impacted by the prolonged decline in commodity prices that began in late 2014. In response, we executed the following actions during 2015 and 2016 aimed at preserving liquidity, reducing overall debt levels and extending debt maturities:

- Completed the Oklahoma Divestitures for \$292.6 million;
- Reduced our 2016 capital expenditures by 75%, as compared to 2015 capital expenditures of approximately \$65 million;
- Completed two debt exchanges reducing debt maturing in 2017 from \$350 million to \$22.7 million;

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- Reduced total debt 32% from \$425 million at December 31, 2014 to \$290.3 million at December 31, 2016;
- Entered into a new \$50 million Multidraw Term Loan Agreement maturing in 2020;
- Suspended the quarterly dividend on our outstanding Series B Preferred Stock saving \$5.1 million annually; and
- Secured a new drilling joint venture in East Texas.

In addition to extending the maturity on approximately \$113.0 million of debt due in 2017 to 2021, our September 2016 debt exchange permits us to reduce our cash interest expense on \$243.5 million of debt from 10% cash to 1% cash and 9% payment-in-kind for the first three semi-annual interest payments, which is expected to provide us with more than \$30 million of cash interest savings during 2017 and 2018. To enhance our liquidity and provide capital to address the remaining 2017 Notes, in October 2016, we entered into a new \$50 million Multidraw Term Loan Agreement maturing in 2020, that replaced our prior bank credit facility which had no borrowing base on the date of termination. We currently have a more favorable outlook on oil and gas prices for 2017 than prices we experienced in 2016. We have recently recompleted our Thunder Bayou well in South Louisiana into a larger sand package and commenced the East Texas joint venture drilling program where we expect to drill eight to ten gross wells during 2017. As a result, we expect to begin growing production during 2017 as compared to 2016.

### Critical Accounting Policies

#### Reserve Estimates

Our estimates of proved oil and gas reserves constitute 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. At the end of each year, our proved reserves are estimated by independent petroleum engineers in accordance with guidelines established by the SEC. These estimates, however, represent projections based on geologic and engineering data. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quantity and quality of available data, engineering and geological interpretation and professional judgment. Estimates of economically recoverable oil and gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effect of regulations by governmental agencies, and assumptions governing future oil and gas prices, future operating costs, severance taxes, development costs and workover costs. The future drilling costs associated with reserves assigned to proved undeveloped locations may ultimately increase to the extent that these reserves may be later determined to be uneconomic. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of our oil and gas properties and/or the rate of depletion of such oil and gas properties.

Disclosure requirements under Staff Accounting Bulletin No. 113 (“SAB 113”) include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. The rules also allow companies the option to disclose probable and possible reserves in addition to the existing requirement to disclose proved reserves. The disclosure requirements also require companies to report the independence and qualifications of third party preparers of reserves and file reports when a third party is relied upon to prepare reserves estimates. Pricing is based on a 12-month, first day of month, average price during the 12-month period prior to the ending date of the balance sheet to report oil and natural gas reserves. In addition, the 12-month average is also used to measure ceiling test impairments and to compute depreciation, depletion and amortization.

#### Full Cost Method of Accounting

We use the full cost method of accounting for our investments in oil and gas properties. Under this method, all acquisition, exploration and development costs, including certain related employee costs, incurred for the purpose of exploring for and developing oil and natural gas are capitalized. Acquisition costs include costs incurred to purchase, lease or otherwise acquire property. Exploration costs include the costs of drilling exploratory wells, including those in progress and geological and geophysical service costs in exploration activities. Development costs include the costs of drilling development wells and costs of completions, platforms, facilities and pipelines. Costs associated with production and general corporate activities are expensed in the period incurred. Sales of oil and gas properties, whether or not being amortized currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and gas.

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The costs associated with unevaluated properties are not initially included in the amortization base and primarily relate to ongoing exploration activities, unevaluated leasehold acreage and delay rentals, seismic data and capitalized interest. These costs are either transferred to the amortization base with the costs of drilling the related well or are assessed quarterly for possible impairment or reduction in value.

We compute the provision for depletion of oil and gas properties using the unit-of-production method based upon production and estimates of proved reserve quantities. Unevaluated costs and related carrying costs are excluded from the amortization base until the properties associated with these costs are evaluated. In addition to costs associated with evaluated properties, the amortization base includes estimated future development costs related to non-producing reserves. Our depletion expense is affected by the estimates of future development costs, unevaluated costs and proved reserves, and changes in these estimates could have an impact on our future earnings.

We capitalize certain internal costs that are directly identified with acquisition, exploration and development activities. The capitalized internal costs include salaries, employee benefits, costs of consulting services and other related expenses and do not include costs related to production, general corporate overhead or similar activities. We also capitalize a portion of the interest costs incurred on our debt. Capitalized interest is calculated using the amount of our unevaluated properties and our effective borrowing rate.

Capitalized costs of oil and gas properties, net of accumulated depreciation, depletion and amortization ("DD&A") and related deferred taxes, are limited to the estimated future net cash flows from proved oil and gas reserves, including the effect of cash flow hedges in place, discounted at 10 percent, plus the lower of cost or fair value of unproved properties, as adjusted for related income tax effects (the full cost ceiling). If capitalized costs exceed the full cost ceiling, the excess is charged to write-down of oil and gas properties in the quarter in which the excess occurs.

Given the volatility of oil and gas prices, it is probable that our estimate of discounted future net cash flows from estimated proved oil and gas reserves will change in the near term. If oil or gas prices remain at current levels or decline further, even for only a short period of time, or if we have downward revisions to our estimated proved reserves, it is possible that further write-downs of oil and gas properties could occur in the future.

### Future Abandonment Costs

Future abandonment costs include costs to dismantle and relocate or dispose of our production platforms, gathering systems, wells and related structures and restoration costs of land and seabed. We develop estimates of these costs for each of our properties based upon the type of production structure, depth of water, reservoir characteristics, depth of the reservoir, market demand for equipment, currently available procedures and consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including changing technology, the timing of estimated costs, the impact of future inflation on current cost estimates and the political and regulatory environment.

### Derivative Instruments

We seek to reduce our exposure to commodity price volatility by hedging a portion of our production through commodity derivative instruments. The estimated fair values of our commodity derivative instruments are recorded in the consolidated balance sheet. The changes in fair value of those derivative instruments that qualify for hedge accounting treatment are recorded in other comprehensive income (loss) until the hedged oil or natural gas quantities are produced. If a hedge becomes ineffective because the hedged production does not occur, or the hedge otherwise does not qualify for hedge accounting treatment, the changes in the fair value of the derivative are recorded in the income statement as derivative income (expense).

Our hedges are specifically referenced to NYMEX prices for natural gas. We evaluate the effectiveness of our hedges at the time we enter the contracts, and periodically over the life of the contracts, by analyzing the correlation between NYMEX and the posted prices we receive from our designated production. Through this analysis, we are able to determine if a high correlation exists between the prices received for the designated production and the NYMEX price at which the hedges will be settled. At December 31, 2016, our derivative instruments were designated effective cash flow hedges.

Estimating the fair value of derivative instruments requires valuation calculations incorporating estimates of future NYMEX prices, discount rates and price movements. As a result, we calculate the fair value of our commodity derivatives using an independent third-party's valuation model that utilizes market-corroborated inputs that are observable over the term of the derivative contract. Our fair value calculations also incorporate an estimate of the counterparties' default risk for derivative assets and an estimate of our default risk for derivative liabilities.

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### Results of Operations

The following table sets forth certain information with respect to our oil and gas operations for the periods noted. These historical results are not necessarily indicative of results to be expected in future periods.

	Year Ended December 31,		
	2016	2015	2014
<b>Production:</b>			
Oil (Bbls)	502,201	528,529	802,509
Gas (Mcf)	16,616,578	25,501,851	31,027,671
Ngl (Mcf)	3,870,947	5,487,239	7,482,310
Total Production (Mcf)	23,500,731	34,160,264	43,325,035
<b>Sales:</b>			
Total oil sales	\$ 20,613,964	\$ 26,532,240	\$ 78,176,377
Total gas sales	37,962,622	75,070,130	114,613,267
Total ngl sales	8,090,292	14,367,024	32,231,090
Total oil and gas sales	\$ 66,666,878	\$ 115,969,394	\$ 225,020,734
<b>Average sales prices:</b>			
Oil (per Bbl)	\$ 41.05	\$ 50.20	\$ 97.41
Gas (per Mcf)	2.28	2.94	3.69
Ngl (per Mcfe)	2.09	2.62	4.31
Per Mcfe	2.84	3.39	5.19

The above sales and average sales prices include increases (reductions) to revenue related to the settlement of gas hedges of \$1,811,000, \$15,940,000 and (\$4,237,000), oil hedges of \$0, \$644,000 and \$897,000, and Ngl hedges of \$0, \$530,000 and \$296,000 for the twelve months ended December 31, 2016, 2015 and 2014, respectively.

### Comparison of Results of Operations for the Years Ended December 31, 2016 and 2015

Net loss available to common stockholders totaled \$96,245,000 and \$299,929,000 for the years ended December 31, 2016 and 2015, respectively. The primary fluctuations were as follows:

**Production** Total production decreased 31% during the year ended December 31, 2016 as compared to the 2015 period. The decrease in total production was due primarily to the Oklahoma Divestitures and normal production declines at our Gulf Coast and East Texas fields as a result of the reduction in capital expenditures during 2016. As a result of the successful recompletion of our Thunder Bayou well in the first quarter of 2017 as well as the commencement of our East Texas drilling program, we expect our total production in 2017 to be higher than production during 2016.

Gas production during the year ended December 31, 2016 decreased 35% from the 2015 period. The decrease in gas production was primarily the result of the Oklahoma Divestitures and normal production declines at our Gulf Coast and East Texas fields. As a result of the successful recompletion of our Thunder Bayou well during the first quarter of 2017 and our drilling program in East Texas, we expect our 2017 average daily gas production to increase as compared to 2016.

Oil production during the year ended December 31, 2016 decreased 5% as compared to the 2015 period due primarily to normal production declines at our Gulf Coast and East Texas fields and downtime due to pipeline constraints at one of our Gulf of Mexico properties. As a result of the successful recompletion of our Thunder Bayou well during the first quarter of 2017 and our drilling program in East Texas, we expect our average daily oil production to increase during 2017 as compared to 2016.

Ngl production during the year ended December 31, 2016 decreased 29% from the 2015 period primarily due to the Oklahoma Divestitures and normal production declines at certain of our Gulf Coast and East Texas fields. As a result of the successful recompletion of our Thunder Bayou well during the first quarter of 2017 and our drilling program in East Texas, we expect our daily Ngl production for 2017 to increase compared to that of 2016.

**Prices** Including the effects of our hedges, average gas prices per Mcf for the year ended December 31, 2016 were \$2.28 as compared to \$2.94 for the 2015 period. Average oil prices per Bbl for the year ended December 31, 2016 were \$41.05 as compared to \$50.20 for the 2015 period and average Ngl prices per Mcfe were \$2.09 for the year ended December 31, 2016, as compared to \$2.62 for the 2015 period. Stated on an Mcfe basis, unit prices received during the year ended December 31, 2016 were 16% lower than the prices received during the 2015 period.

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**Revenue** Including the effects of hedges, oil and gas sales during the twelve months ended December 31, 2016 decreased 43% to \$66,667,000, as compared to oil and gas sales of \$115,969,000 during the 2015 period. The decreased revenue during 2016 was primarily the result of the decreased production during 2016 as discussed above, as well as lower average realized prices.

**Expenses** Lease operating expenses for the year ended December 31, 2016 totaled \$28,508,000, or \$1.21 per Mcfe, as compared to \$40,130,000, or \$1.17 per Mcfe, during the 2015 period. The decrease in total lease operating expenses for the year ended December 31, 2016 is primarily a result of the Oklahoma Divestitures. Additionally, lease operating expenses decreased overall at our Gulf Coast and East Texas fields as a result of certain cost saving measures put in place during 2016. We expect lease operating expenses during 2017 to generally approximate 2016 expenses on an absolute value basis and to decrease on a per unit basis.

Production taxes for the year ended December 31, 2016 totaled \$354,000, or \$0.02 per Mcfe, as compared to \$2,470,000, or \$0.07 per Mcfe, during the 2015 period. The decrease in total production taxes was primarily due to the receipt in 2016 of \$1,292,000 of production tax refunds on certain of our East Texas wells that qualified for a gas tax credit. Additionally, production taxes decreased as a result of lower commodity prices for our production during the 2016 period as compared to the 2015 period. The majority of our properties that are subject to severance taxes are assessed on the oil and gas sales value. As a result of the expected increases in production and completion of the two-year severance tax exemption on our Thunder Bayou well, we expect an increase in our total and per unit production taxes during 2017 as compared to 2016.

General and administrative expenses during the year ended December 31, 2016 totaled \$26,040,000 as compared to \$20,777,000 during the 2015 period. General and administrative expenses increased 25% during the year ended December 31, 2016 primarily due to the inclusion of \$10,139,000 of costs related to the issuance of the 2021 Notes and 2021 PIK Notes. ASC Topic 470-60 "Troubled Debt Restructurings by Debtors" requires financing costs related to a troubled debt restructuring to be expensed in the period incurred. Offsetting this increase were lower employee related costs, including share-based compensation. Included in general and administrative expenses for 2016 are share-based compensation costs, net of amounts capitalized, of \$1,582,000, compared to \$4,388,000 during the 2015 period. We capitalized \$6,623,000 of general and administrative costs during the year ended December 31, 2016 as compared to \$8,210,000 during the comparable 2015 period. Excluding the non-recurring debt restructuring fees included in 2016, we expect general and administrative expenses to decrease during 2017 as compared to 2016 due to an approximate 50% reduction in staff levels during 2016.

Depreciation, depletion and amortization ("DD&A") expense on oil and gas properties for the year ended December 31, 2016 totaled \$27,962,000, or \$1.19 per Mcfe, as compared to \$62,138,000, or \$1.82 per Mcfe, during the comparable 2015 period. The decrease in the per unit DD&A rate is primarily the result of recent ceiling test write-downs. We expect our DD&A rate for 2017 to approximate the rate during 2016.

At December 31, 2016, the prices used in computing the estimated future net cash flows from our estimated proved reserves, including the effect of hedges in place at that date, averaged \$2.51 per Mcf of natural gas, \$40.85 per barrel of oil and \$1.82 per Mcfe of natural gas liquids, respectively. As a result of lower commodity prices and their negative impact on our estimated proved reserves and estimated future net cash flows, we recognized a ceiling test write-down of approximately \$40,304,000 during the year ended December 31, 2016. At December 31, 2015, the prices used in computing the estimated future net cash flows from our estimated proved reserves, including the effect of hedges in place at that date, averaged \$2.42 per Mcf of natural gas, \$50.29 per barrel of oil and \$2.21 per Mcfe of natural gas liquids, respectively. As a result of lower commodity prices and their negative impact on our estimated proved reserves and estimated future net cash flows, we recognized a ceiling test write-down of approximately \$266,562,000 during the year ended December 31, 2015. See Note 11, "Ceiling Test" for further discussion of the ceiling test write-downs. Utilizing current strip prices for oil and gas prices for the first quarter of 2017 and projecting the effect on the estimated future net cash flows from our estimated proved reserves as of March 31, 2017, we do not expect to recognize an additional ceiling test write-down during the first quarter of 2017.

Interest expense, net of amounts capitalized on unevaluated properties, totaled \$30,019,000 during the year ended December 31, 2016, as compared to \$33,766,000 during 2015. During the year ended December 31, 2016, our capitalized interest totaled \$935,000 as compared to \$4,671,000 during the 2015 period. The decrease in interest expense was a result of the February 2016 debt exchange, including a \$1,479,000 non-cash reduction related to the amortization of the excess carrying value of the 2017 Notes tendered in the February 2016 debt exchange and the 2021 Notes tendered in the September 2016 debt exchange (see Note 9 - Long-Term Debt). In addition, during the February 2016 debt exchange, we redeemed \$53,627,000 of 2017 Notes with cash on hand. Partially offsetting this decrease in interest expense was the decrease in capitalized interest as a result of lower unevaluated oil and gas properties. While we expect interest expense for 2017 to approximate 2016, cash interest costs during 2017 are expected to be significantly lower than those in 2016 due to the payment-in-kind feature of the 2021 PIK Notes.

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Income tax expense during the year ended December 31, 2016 totaled \$543,000, as compared to \$2,626,000 during the 2015 period. We typically provide for income taxes at a statutory rate of 35% adjusted for permanent differences expected to be realized, primarily statutory depletion, non-deductible stock compensation expenses and state income taxes.

As a result of the ceiling test write-downs recognized, we have incurred a three-year cumulative loss. Because of the impact the cumulative loss has on the determination of the recoverability of deferred tax assets through future earnings, we assessed the realizability of our deferred tax assets based on the future reversals of existing deferred tax liabilities. Accordingly, we established a valuation allowance for a portion of our deferred tax asset. The valuation allowance was \$177,405,000 as of December 31, 2016.

### Comparison of Results of Operations for the Years Ended December 31, 2015 and 2014

Net income (loss) available to common stockholders totaled (\$299,929,000) and \$26,051,000 for the years ended December 31, 2015 and 2014, respectively. The primary fluctuations were as follows:

**Production** Total production decreased 21% during the year ended December 31, 2015 as compared to the 2014 period. The decrease in total production was due primarily to the 2015 Oklahoma divestiture and normal production declines at our Gulf Coast fields. Partially offsetting these decreases were increases relating to the successful drilling program in our Carthage field as well as our Thunder Bayou discovery.

Gas production during the year ended December 31, 2015 decreased 18% from the 2014 period. The decrease in gas production was due to the 2015 Oklahoma divestiture and normal production declines at our Gulf Coast fields, partially offset by the successful drilling program in our Carthage field and the completion of our Thunder Bayou discovery.

Oil production during the year ended December 31, 2015 decreased 34% as compared to the 2014 period due primarily to normal production declines at our Gulf Coast fields, downtime at certain of our Gulf of Mexico properties and the divestiture of our Fort Trinidad field in July 2015 and our Eagleford field in September 2014.

Ngl production during the year ended December 31, 2015 decreased 27% from the 2014 period due to the 2015 Oklahoma divestiture and normal production declines at our Gulf Coast fields, partially offset by the successful drilling program in our Carthage field and the completion of our Thunder Bayou discovery.

**Prices** Including the effects of our hedges, average gas prices per Mcf for the year ended December 31, 2015 were \$2.94 as compared to \$3.69 for the 2014 period. Average oil prices per Bbl for the year ended December 31, 2015 were \$50.20 as compared to \$97.41 for the 2014 period and average Ngl prices per Mcfe were \$2.62 for the year ended December 31, 2015, as compared to \$4.31 for the 2014 period. Stated on an Mcfe basis, unit prices received during the year ended December 31, 2015 were 35% lower than the prices received during the 2014 period.

**Revenue** Including the effects of hedges, oil and gas sales during the twelve months ended December 31, 2015 decreased 48% to \$115,969,000, as compared to oil and gas sales of \$225,021,000 during the 2014 period. The decreased revenue during 2015 was primarily due to decreased production during 2015 as a result of the 2015 Oklahoma divestiture, as well as lower average realized prices.

**Expenses** Lease operating expenses for the year ended December 31, 2015 totaled \$40,130,000, or \$1.17 per Mcfe, as compared to \$48,597,000, or \$1.12 per Mcfe, during the 2014 period. The increase in per unit lease operating expenses for the year ended December 31, 2015 is primarily a result of the 2015 Oklahoma divestiture, which included properties with a lower relative per unit cost, as well as normal production declines and downtime at certain of our Gulf Coast fields.

Production taxes for the year ended December 31, 2015 totaled \$2,470,000, or \$0.07 per Mcfe, as compared to \$5,927,000, or \$0.14 per Mcfe, during the 2014 period. The decrease in total production taxes was primarily due to lower commodity prices for our production during the 2015 period as compared to the 2014 period. The majority of our properties that are subject to severance taxes are assessed on the oil and gas sales value.

General and administrative expenses during the year ended December 31, 2015 totaled \$20,777,000 as compared to \$22,870,000 during the 2014 period. General and administrative expenses decreased 9% during the year ended December 31, 2015 primarily due to lower employee related costs including share-based compensation during the 2015 period which was only partially offset by lower capitalized costs. Included in general and administrative expenses for 2015 are share-based compensation costs, net of amounts capitalized, of \$4,388,000, compared to \$6,808,000 during the 2014 period. We capitalized \$8,210,000 of general and administrative costs during the year ended December 31, 2015 as compared to \$12,122,000 during the comparable 2014 period.

Depreciation, depletion and amortization ("DD&A") expense on oil and gas properties for the year ended December 31, 2015 totaled \$62,138,000, or \$1.82 per Mcfe, as compared to \$86,406,000, or \$1.99 per Mcfe, during the comparable 2014 period. The decrease in the per unit DD&A rate is primarily the result of ceiling test write-downs in the 2015 period.



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At December 31, 2015, the prices used in computing the estimated future net cash flows from our estimated proved reserves, including the effect of hedges in place at that date, averaged \$2.42 per Mcf of natural gas, \$50.29 per barrel of oil and \$2.21 per Mcfe of natural gas liquids, respectively. As a result of lower commodity prices and their negative impact on our estimated proved reserves and estimated future net cash flows, we recognized a ceiling test write-down of approximately \$266,562,000 during the year.

Interest expense, net of amounts capitalized on unevaluated properties, totaled \$33,766,000 during the year ended December 31, 2015, as compared to \$29,281,000 during 2014. During the year ended December 31, 2015, our capitalized interest totaled \$4,671,000 as compared to \$9,999,000 during the 2014 period. The increase in interest expense was a result of lower capitalized interest on our reduced unevaluated property balance which declined as a result of the 2015 Oklahoma divestiture.

Income tax expense (benefit) during the year ended December 31, 2015 totaled \$2,626,000, as compared to (\$2,941,000) during the 2014 period. We typically provide for income taxes at a statutory rate of 35% adjusted for permanent differences expected to be realized, primarily statutory depletion, non-deductible stock compensation expenses and state income taxes.

As a result of the ceiling test write-downs recognized, we have incurred a three-year cumulative loss. Because of the impact the cumulative loss has on the determination of the recoverability of deferred tax assets through future earnings, we assessed the realizability of our deferred tax assets based on the future reversals of existing deferred tax liabilities. Accordingly, we established a valuation allowance for a portion of our deferred tax asset. The valuation allowance was \$143,508,000 as of December 31, 2015.

### Liquidity and Capital Resources

We have historically financed our acquisition, exploration and development activities principally through cash flow from operations, borrowings from banks and other lenders, issuances of equity and debt securities, joint ventures and sales of assets. However, our liquidity position has been negatively impacted by the prolonged decline in commodity prices that began in late 2014. In response to lower commodity prices, we executed a number of transactions during 2015 and 2016 aimed at preserving liquidity, reducing overall debt levels and extending debt maturities. Through these transactions, which included two debt exchanges, we have reduced debt maturing in 2017 from \$350 million to \$22.7 million and have reduced total debt 32% from \$425 million at December 31, 2014 to \$290.3 million at December 31, 2016. In addition to extending the maturity on the majority of our debt due in 2017, our September 2016 debt exchange permits us to reduce our cash interest expense on \$243.5 million of debt from 10% cash to 1% cash and 9% payment-in-kind for the first three semi-annual interest payments, which is expected to provide us with more than \$30 million in cash interest savings during 2017 and 2018. Finally, in October 2016, we entered into a new \$50 million Multidraw Term Loan Agreement maturing in 2020 that replaced our prior bank credit facility, which had no borrowing base on the date of termination. The Multidraw Term Loan Agreement will provide capital for general corporate purposes, including refinancing the \$22.7 million of remaining 2017 Notes. For additional information, see "Source of Capital: Debt" below.

At December 31, 2016 we had a working capital deficit of \$37.8 million compared to a surplus of \$50.5 million at December 31, 2015. The decrease in our working capital is primarily due to the \$63.8 million in cash payments made in connection with the 2016 debt exchanges and the inclusion of the 2017 Notes in current liabilities as discussed in "Source of Capital: Debt" below.

Our liquidity may be negatively impacted by federal bonding requirements related to our properties located on the Outer Continental Shelf (the "OCS"). To cover the various obligations of lessees on the OCS, the Bureau of Ocean Energy Management (the "BOEM") and the Bureau of Safety and Environmental Enforcement (the "BSEE") generally require that lessees have substantial net worth or post bonds or other acceptable assurances that such obligations will be satisfied. Because we are not exempt from the BOEM's supplemental bonding requirements, we engage surety companies to post the requisite bonds. Pursuant to the terms of our surety agreements, we may be required to post collateral at the surety companies' discretion. Two of our surety companies requested collateral be posted to support certain of the bonds issued on our behalf and to date, we have provided cash deposits totaling \$6.2 million to satisfy these requests. The surety companies may request additional collateral which could have a material adverse effect on our liquidity position. If we fail to satisfy future requests for collateral, we may be in default under our agreements with the surety companies, which could cause a cross-default under the Multidraw Term Loan Agreement and potentially the indentures governing the 2021 Notes and 2021 PIK Notes. In addition, recently updated BOEM financial assurance and risk management requirements may increase the amount of surety bonds or other security required to be provided by us. For additional information, see "Item 1A Risk Factors - We may be required to post additional collateral to satisfy the collateral requirements related to the surety bonds that secure our offshore decommissioning obligations or to increase the amount of surety bonds or other security required pursuant to updated BOEM financial assurance and risk management requirements".

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### Source of Capital: Operations

Net cash flow provided by (used in) operations decreased from \$30.1 million during the year ended December 31, 2015 to \$(56.6) million during the 2016 period. The decrease in operating cash flow during 2016 as compared to 2015 was primarily attributable to decreases in oil and gas revenues as well as the timing of payment of payables based on operational activity.

### Source of Capital: Divestitures

We do not budget property divestitures; however, we are continuously evaluating our property base to determine if there are assets in our portfolio that no longer meet our strategic objectives. From time to time we may divest certain assets in order to provide liquidity to strengthen our balance sheet or provide capital to be reinvested in higher rate of return projects. We are currently exploring divestment opportunities for certain of our legacy Gulf of Mexico assets. We cannot assure you that we will be able to sell any of our assets in the future.

In June 2015, we sold a majority of our interests in the Woodford and Mississippian Lime fields for cash proceeds of \$274.1 million. Net proceeds from the sale were used to repay all borrowings outstanding under our bank credit facility and increase our cash on hand. In 2016, we sold our remaining assets in Oklahoma for approximately \$18.5 million.

### Source of Capital: Debt

On August 19, 2010, we issued \$150 million in principal amount of our 10% Senior Notes due 2017. On July 3, 2013, we issued an additional \$200 million in principal amount of our 10% Senior Notes due 2017 (collectively, the "2017 Notes").

On February 17, 2016, we closed a private exchange offer (the "February Exchange") and consent solicitation (the "February Consent Solicitation") to certain eligible holders of our outstanding 2017 Notes. In satisfaction of the tender of \$214.4 million in aggregate principal amount of the 2017 Notes, representing approximately 61% of the then outstanding aggregate principal amount of 2017 Notes, we (i) paid approximately \$53.6 million of cash, (ii) issued \$144.7 million aggregate principal amount of our new 10% Second Lien Senior Secured Notes due 2021 (the "2021 Notes") and (iii) issued approximately 4.3 million shares (1.1 million shares as adjusted for the Reverse Split) of our common stock. Following the completion of the February Exchange, \$135.6 million in aggregate principal amount of the 2017 Notes remained outstanding. The February Consent Solicitation eliminated or waived substantially all of the restrictive covenants contained in the indenture governing the 2017 Notes.

On September 27, 2016, we closed private exchange offers (the "September Exchange") and a consent solicitation (the "September Consent Solicitation") to certain eligible holders of our outstanding 2017 Notes and 2021 Notes. In satisfaction of the consideration of \$113.0 million in aggregate principal amount of the 2017 Notes, representing approximately 83% of the then outstanding aggregate principal amount of 2017 Notes, and \$130.5 million in aggregate principal amount of the then 2021 Notes, representing approximately 90% of the then outstanding aggregate principal amount of 2021 Notes, we issued (i) \$243.5 million in aggregate principal amount of our new 10% Second Lien Senior Secured PIK Notes due 2021 (the "2021 PIK Notes") and (ii) approximately 3.5 million shares of our common stock. We also paid, in cash, accrued and unpaid interest on the 2017 Notes and 2021 Notes accepted in the September Exchange from the last applicable interest payment date to, but not including, September 27, 2016. Following the consummation of the September Exchange, there is \$22.7 million in aggregate principal amount of the 2017 Notes outstanding and \$14.2 million in aggregate principal amount of the 2021 Notes outstanding. The September Consent Solicitation amended certain provisions of the indenture governing the 2021 Notes and amended the registration rights agreement with respect to the 2021 Notes.

Unless we exercise our payable in kind ("PIK") interest option, the 2021 PIK Notes bear interest at a rate of 10% per annum on the principal amount and interest is payable semi-annually in arrears on February 15 and August 15 of each year, starting on February 15, 2017. We may, at our option, for one or more of the first three interest payment dates of the 2021 PIK Notes, pay interest at (i) the annual rate of 1% in cash plus (ii) the annual rate of 9% PIK (the "PIK Interest") payable by increasing the principal amount outstanding of the 2021 PIK Notes or by issuing additional 2021 PIK Notes in certificated form. We exercised this PIK option in connection with the interest payment on February 15, 2017. As of the date hereof, we are in compliance with all of the covenants under the 2021 PIK Notes.

The 2021 Notes bear interest at a rate of 10% per annum on the principal amount and interest is payable semi-annually in arrears on February 15 and August 15 of each year. As of the date hereof, we are in compliance with all of the covenants under the 2021 Notes.

The 2017 Notes bear interest at a rate of 10% per annum on the principal amount and interest is payable semi-annually in arrears on March 1 and September 1 of each year and the 2017 Notes mature on September 1, 2017. As of the date hereof, we are in compliance with the remaining covenants under the 2017 Notes. On March 1, 2017, we notified the holders of the 2017 Notes that we will redeem the remaining \$22.7 million of 2017 Notes on March 31, 2017 at a redemption price of 100% of the principal amount thereof, plus accrued interest to the redemption date. We expect to pay the redemption price with a combination of cash on hand and amounts borrowed under the Multidraw Term Loan Agreement described below.

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The February Exchange and September Exchange were accounted for as troubled debt restructurings pursuant to Accounting Standards Codification ("ASC") Topic 470-60 "Troubled Debt Restructurings by Debtors." We determined that the future undiscounted cash flows from the 2021 PIK Notes issued in the September Exchange through the maturity date exceeded the adjusted carrying amount of the 2017 Notes and the 2021 Notes tendered in the September Exchange. Accordingly, no gain or loss on extinguishment of debt was recognized in connection with the September Exchange. The net shortfall of the remaining carrying value of the 2017 Notes and 2021 Notes tendered as compared to the principal amount of the 2021 PIK Notes issued in the September Exchange of \$0.6 million is reflected as part of the carrying value of the 2021 PIK Notes. Such shortfall is being amortized under the effective interest method over the term of the 2021 PIK Notes.

We previously determined that the future undiscounted cash flows from the 2021 Notes issued in the February Exchange through the maturity date exceeded the adjusted carrying amount of the 2017 Notes tendered in the February Exchange. Accordingly, no gain on extinguishment of debt was recognized in connection with the February Exchange. The excess of the remaining carrying value of the 2017 Notes tendered over the principal amount of the 2021 Notes issued in the February Exchange of \$13.9 million was reflected as part of the carrying value of the 2021 Notes. The amount of the excess carrying value attributable to the 2021 Notes tendered in the September Exchange is now reflected as part of the carrying value of the 2021 PIK Notes. The excess carrying value attributable to the remaining 2021 Notes is being amortized under the effective interest method over the term of the 2021 Notes. At December 31, 2016, \$1.2 million of the excess remained as part of the carrying value of the 2021 Notes and we recognized \$1.5 million of amortization expense as a reduction to interest expense during the year ended December 31, 2016.

The indentures governing the 2021 PIK Notes and the 2021 Notes contain affirmative and negative covenants that, among other things, limit our ability and the ability of the subsidiary guarantors of the 2021 PIK Notes and the 2021 Notes to incur indebtedness; purchase or redeem stock; make certain investments; create liens that secure debt; enter into transactions with affiliates; sell assets; refinance certain indebtedness; merge with or into other companies or transfer substantially all of our assets; and, in certain circumstances, to pay dividends or make other distributions on stock. The 2021 PIK Notes and the 2021 Notes are fully and unconditionally guaranteed on a senior basis by certain of our wholly-owned subsidiaries.

The 2021 PIK Notes and the 2021 Notes are secured equally and ratably by second-priority liens on substantially all of our and the subsidiary guarantors' oil and gas properties and substantially all of our other assets to the extent such properties and assets secure the Multidraw Term Loan Agreement (as defined below), except for certain excluded assets. Pursuant to the terms of an intercreditor agreement, the security interest in those properties and assets that secure the 2021 PIK Notes and the 2021 Notes and the guarantees are contractually subordinated to liens that secure the Multidraw Term Loan Agreement and certain other permitted indebtedness. Consequently, the 2021 PIK Notes and the 2021 Notes and the guarantees will be effectively subordinated to the Multidraw Term Loan Agreement and such other indebtedness to the extent of the value of such assets.

On October 17, 2016, we entered into the Multidraw Term Loan Agreement (the "Multidraw Term Loan Agreement") with Franklin Custodian Funds - Franklin Income Fund ("Franklin"), as a lender, and Wells Fargo Bank, National Association, as administrative agent, replacing the credit agreement with JPMorgan Chase Bank, N.A. The Multidraw Term Loan Agreement provides a multi-advance term loan facility, with borrowing availability for three years, in a principal amount of up to \$50.0 million. The loans drawn under the Multidraw Term Loan Agreement (collectively, the "Term Loans") may be used to repay existing debt, including the 2017 Notes, to pay transaction fees and expenses, to provide working capital for exploration and production operations and for general corporate purposes. The Term Loans mature on October 17, 2020. As of the date hereof, we have \$10.0 million of borrowings outstanding under the Term Loans.

Our obligations under the Multidraw Term Loan Agreement and the Term Loans are secured by a first priority lien on substantially all of our assets and certain of our subsidiaries, including a lien on all equipment and at least 90% of the aggregate total value of our oil and gas properties and our subsidiaries, a pledge of the equity interests of PetroQuest Energy, L.L.C. (the "Borrower") and certain of our other subsidiaries, and corporate guarantees of our and certain of our other subsidiaries of the indebtedness of the Borrower. Term Loans under the Multidraw Term Loan Agreement bear interest at the rate of 10% per annum.

We and our subsidiaries are subject to a restrictive financial covenant under the Multidraw Term Loan Agreement, consisting of maintaining a ratio of (i) the present value, discounted at 10% per annum, of the estimated future net revenues in respect of our and our subsidiaries' oil and gas properties, before any state, federal, foreign or other income taxes, attributable to proved developed reserves, using three-year strip prices in effect at the end of each calendar quarter, including swap agreements in place at the end of each quarter, to (ii) the sum of the outstanding Term Loans and the then outstanding commitments to provide Term Loans, that shall not be less than (a) 1.7 to 1.0 as measured on December 31, 2016 and March 31, 2017, and (b) 2.0 to 1.0 as measured on June 30, 2017, and the last day of each calendar quarter thereafter (the "Coverage Ratio").

Sales of our and our subsidiaries' oil and gas properties outside the ordinary course of business are limited under the terms of the Multidraw Term Loan Agreement. In addition, the Multidraw Term Loan Agreement prohibits us from declaring and paying dividends on our Series B Preferred Stock.

The Multidraw Term Loan Agreement also includes customary restrictions with respect to debt, liens, dividends, distributions and redemptions, investments, loans and advances, nature of business, international operations and foreign

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subsidiaries, leases, sale or discount of receivables, mergers or consolidations, sales of properties, transactions with affiliates, negative pledge agreements, gas imbalances and swap agreements. As of the date hereof, no default or event of default exists under the Multidraw Term Loan Agreement and we were in compliance with all covenants contained in the Multidraw Term Loan Agreement including the Coverage Ratio.

The 2017 Notes are reflected net of \$0.1 million and \$3.0 million of related unamortized financing costs at December 31, 2016 and 2015, respectively. The 2021 Notes are reflected net of \$0.1 million of related unamortized financing costs as of December 31, 2016 and the Term Loans are reflected net of \$2.8 million of related unamortized financing costs as of December 31, 2016.

The following table reconciles the face value of the 2017 Notes, 2021 Notes, 2021 PIK Notes and Term Loans to the carrying value included in our Consolidated Balance Sheet as of December 31, 2016 and 2015 (in thousands):

	December 31, 2016				December 31, 2015			
	<u>2017 Notes</u>	<u>2021 Notes</u>	<u>2021 PIK Notes</u>	<u>Term Loans</u>	<u>2017 Notes</u>	<u>2021 Notes</u>	<u>2021 PIK Notes</u>	<u>Term Loans</u>
Face Value	\$ 22,650	\$ 14,177	\$ 243,468	\$ 10,000	\$ 350,000	\$ —	\$ —	\$ —
Unamortized Deferred Financing Costs	(82)	(108)	—	(2,751)	(2,992)	—	—	—
Excess (shortfall) Carrying Value	—	1,159	(590)	—	—	—	—	—
Accrued PIK Interest	—	—	5,722	—	—	—	—	—
Carrying Value	<u>\$ 22,568</u>	<u>\$ 15,228</u>	<u>\$ 248,600</u>	<u>\$ 7,249</u>	<u>\$ 347,008</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ —</u>

### Use of Capital: Exploration and Development

Our 2017 capital budget, which includes capitalized interest and general and administrative costs, is expected to range between \$40 million and \$48 million, which from the midpoint of such range, represents a 176% increase from our 2016 capital expenditures. Because we operate the majority of our drilling activities, we expect to be able to control the timing of a substantial portion of our capital investments. We plan to fund our capital expenditures with cash flow from operations and cash on hand. To the extent additional capital is required, we may utilize our Multidraw Term Loan Agreement, sales of equity or debt securities, evaluate the sale of additional assets or we may reduce our capital expenditures to manage our liquidity position.

### Use of Capital: Acquisitions

We do not budget acquisitions; however, we are continuously evaluating opportunities to expand our existing asset base or establish positions in new core areas.

We expect to finance our future acquisition activities, if consummated, through cash on hand. We may also utilize sales of equity or debt securities, borrowings under our Multidraw Term Loan Agreement, sales of properties or assets or joint venture arrangements with industry partners, if necessary. We cannot assure you that such additional financings will be available on acceptable terms, if at all.

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### Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2016 (in thousands):

	<b>Total</b>	<b>2017</b>	<b>2018</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>After 2021</b>
10% senior notes due 2017 (1)	\$ 24,915	\$ 24,915	\$ —	\$ —	\$ —	\$ —	\$ —
10% senior secured notes due 2021 (1)	20,558	1,418	1,418	1,418	1,418	14,886	—
10% senior secured PIK Notes due 2021 (1)	392,806	21,997	26,919	27,511	27,511	288,868	—
Multidraw Term Loan (1)	13,922	1,000	1,000	1,000	10,922	—	—
Operating leases (2)	3,815	1,208	470	447	445	434	811
Asset retirement obligations (3)	36,558	4,160	3,535	1,778	20,840	3,751	2,494
Other commitments (4)	12,218	2,318	2,475	2,475	2,475	2,475	—
<b>Total</b>	<b>\$ 504,792</b>	<b>\$ 57,016</b>	<b>\$ 35,817</b>	<b>\$ 34,629</b>	<b>\$ 63,611</b>	<b>\$ 310,414</b>	<b>\$ 3,305</b>

(1) Includes principal and estimated interest.

(2) Consists primarily of leases for office space and office equipment.

(3) Consists of estimated future obligations to abandon our oil and gas properties.

(4) Consists of a drilling rig contract and a volumetric commitment in East Texas.

### Item 7A Quantitative and Qualitative Disclosures About Market Risk

We experience market risks primarily in commodity prices. Because all of our properties are located within the United States, we believe that our business operations are not exposed to significant market risks relating to foreign currency exchange risk.

Our revenues are derived from the sale of our crude oil, natural gas, and natural gas liquids production. Based on projected annual sales volumes for 2017, a 10% decline in the estimated average prices we expect to receive for our crude oil, natural gas and natural gas liquids production would result in an approximate \$8.4 million decline in our revenues for 2017.

We periodically seek to reduce our exposure to commodity price volatility by hedging a portion of our production through commodity derivative instruments. In the settlement of a typical hedge transaction, we will have the right to receive from the counterparties to the hedge the excess of the fixed price specified in the hedge over a floating price based on a market index, multiplied by the quantity hedged. If the floating price exceeds the fixed price, we are required to pay the counterparties this difference multiplied by the quantity hedged. During the year ended December 31, 2016, we received approximately \$1.8 million from the counterparties to our derivative instruments in connection with net hedge settlements.

We are required to pay the difference between the floating price and the fixed price (when the floating price exceeds the fixed price) regardless of whether we have sufficient production to cover the quantities specified in the hedge. Significant reductions in production at times when the floating price exceeds the fixed price could require us to make payments under the hedge agreements even though such payments are not offset by sales of production. Hedging will also prevent us from receiving the full advantage of increases in oil or gas prices above the fixed amount specified in the hedge.

Our Multidraw Term Loan Agreement requires that the counterparties to our hedge contracts be rated A-/A3 or higher by S&P or Moody's. Currently, the counterparty to our existing hedge contracts is Shell Trading Risk Management LLC.

As of December 31, 2016, we had entered into the following gas hedge contracts:

<b>Production Period</b>	<b>Instrument Type</b>	<b>Daily Volumes</b>	<b>Weighted Average Price</b>
<b>Natural Gas:</b>			
January 2017 - December 2017	Swap	10,000 Mmbtu	\$3.26
January 2017 - March 2018	Swap	10,000 Mmbtu	\$3.01
April 2017 - March 2018	Swap	10,000 Mmbtu	\$3.40

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During March 2017, we entered into the following additional hedge contract accounted for as a cash flow hedge:

Production Period	Instrument Type	Daily Volumes	Weighted Average Price
<b>Natural Gas:</b>			
October 2017 - March 2018	Swap	10,000 Mmbtu	\$3.22

After executing the above transactions, the Company has approximately 11.0 Bcf of gas volumes, at an average price of \$3.21 per Mcf hedged for 2017 and approximately 2.7 Bcf of gas volumes, at an average price of \$3.21 per Mcf hedged for 2018.

### Item 8. **Financial Statements and Supplementary Data**

Information concerning this Item begins on page F-1.

### Item 9. **Changes in and Disagreements with Accountants on Accounting and Financial Disclosure**

None.

### Item 9A. **Controls and Procedures**

#### Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, the Company's management, including its Chief Executive Officer and Chief Financial Officer, carried out an evaluation of the effectiveness of the Company's disclosure controls and procedures pursuant to Rule 13a-15 of the Exchange Act. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded the following:

- i. that the Company's disclosure controls and procedures are designed to ensure (a) that information required to be disclosed by the Company in the reports it files or submits under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms, and (b) that such information is accumulated and communicated to the Company's management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure; and
- ii. that the Company's disclosure controls and procedures are effective.

Notwithstanding the foregoing, there can be no assurance that the Company's disclosure controls and procedures will detect or uncover all failures of persons within the Company and its consolidated subsidiaries to disclose material information otherwise required to be set forth in the Company's periodic reports. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures.

#### Changes in Internal Control Over Financial Reporting

There have been no changes in the Company's internal control over financial reporting during the quarter ended December 31, 2016 that have materially affected, or that are reasonably likely to materially affect, the Company's internal control over financial reporting.

#### Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting, and for performing an assessment of the effectiveness of internal control over financial reporting as of December 31, 2016. 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. Our system of internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (ii) 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 (iii) 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.

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

Management performed an assessment of the effectiveness of our internal control over financial reporting as of December 31, 2016 based upon criteria in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework). Based on our assessment, management believes that our internal control over financial reporting was effective as of December 31, 2016 based on these criteria.

Ernst & Young LLP, our independent registered public accounting firm, has issued their report on the effectiveness of the Company's internal control over financial reporting as of December 31, 2016.

March 9, 2017

/s/ Charles T. Goodson

Charles T. Goodson  
Chairman and  
Chief Executive Officer

/s/ J. Bond Clement

J. Bond Clement  
Executive Vice President-  
Chief Financial Officer

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### Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders  
PetroQuest Energy, Inc.

We have audited PetroQuest Energy, Inc.'s internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). PetroQuest Energy, Inc.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

In our opinion, PetroQuest Energy, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the COSO criteria.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the accompanying consolidated balance sheets of PetroQuest Energy, Inc. as of December 31, 2016 and 2015, and the related consolidated statements of operations, comprehensive income (loss), cash flows, and stockholders' equity for each of the three years in the period ended December 31, 2016 and our report dated March 9, 2017 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

New Orleans, Louisiana  
March 9, 2017

#### Item 9B. **Other Information**

NONE

### **PART III**

#### **Items 10, 11, 12, 13, & 14.**

Pursuant to General Instruction G of Form 10-K, the information concerning Item 10. Directors, Executive Officers and Corporate Governance, Item 11. Executive Compensation, Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters, Item 13. Certain Relationships and Related Transactions, and Director Independence and Item 14. Principal Accounting Fees and Services, is incorporated by reference to the information set forth in the definitive Proxy Statement of PetroQuest Energy, Inc. relating to the Annual Meeting of Stockholders to be held May 16, 2017, to be filed pursuant to Regulation 14A under the Securities Exchange Act of 1934 with the Securities and Exchange Commission.



**PART IV**

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

**(a) 1. FINANCIAL STATEMENTS**

The following financial statements of the Company and the Report of the Company's Independent Registered Public Accounting Firm thereon are included on pages F-1 through F-27 of this Form 10-K:

Report of Independent Registered Public Accounting Firm  
Consolidated Balance Sheets as of December 31, 2016 and 2015  
Consolidated Statements of Operations for the three years ended December 31, 2016  
Consolidated Statements of Comprehensive Income (Loss) for the three years ended December 31, 2016  
Consolidated Statements of Cash Flows for the three years ended December 31, 2016  
Consolidated Statements of Stockholders' Equity for the three years ended December 31, 2016  
Notes to Consolidated Financial Statements

**2. FINANCIAL STATEMENT SCHEDULES:**

All schedules are omitted because the required information is inapplicable or the information is presented in the Financial Statements or the notes thereto.

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### 3. EXHIBITS:

- \*\* 2.1 Plan and Agreement of Merger by and among Optima Petroleum Corporation, Optima Energy (U.S.) Corporation, its wholly-owned subsidiary, and Goodson Exploration Company, NAB Financial L.L.C., Dexco Energy, Inc., American Explorer, L.L.C. (incorporated herein by reference to Appendix G of the Proxy Statement on Schedule 14A filed July 22, 1998).
- \*\* 2.2 Purchase and Sale Agreement dated as of June 19, 2013, between PetroQuest Energy, L.L.C. and Hall-Houston Exploration II, L.P. (incorporated herein by reference to Exhibit 2.1 to Form 8-K filed on June 20, 2013).
- \*\* 2.3 Purchase and Sale Agreement dated as of June 19, 2013, between PetroQuest Energy, L.L.C. and Hall-Houston Exploration III, L.P. (incorporated herein by reference to Exhibit 2.2 to Form 8-K filed on June 20, 2013).
- \*\* 2.4 Purchase and Sale Agreement dated as of June 19, 2013, between PetroQuest Energy, L.L.C. and Hall-Houston Exploration IV, L.P. (incorporated herein by reference to Exhibit 2.3 to Form 8-K filed on June 20, 2013).
- \*\* 2.5 Purchase and Sale Agreement dated as of June 19, 2013, between PetroQuest Energy, L.L.C. and GOM-H Exploration, LLC (incorporated herein by reference to Exhibit 2.4 to Form 8-K filed on June 20, 2013).
- \*\*#2.6 Purchase and Sale Agreement dated as of June 4, 2015, by and between PetroQuest Energy, L.L.C. and WSGP Gas Producing, LLC (incorporated herein by reference to Exhibit 2.1 to Form 10-Q filed on August 5, 2015).
- \*\*#2.7 Purchase and Sale Agreement dated as of April 20, 2016, by and between PetroQuest Energy, L.L.C. and GR Woodford Properties, LLC (incorporated herein by reference to Exhibit 2.1 to Form 10-Q filed on August 3, 2016).
- 3.1 Certificate of Incorporation of PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit 4.1 to Form 8-K filed September 16, 1998).
- 3.2 Certificate of Domestication of Optima Petroleum Corporation (incorporated herein by reference to Exhibit 4.4 to Form 8-K filed September 16, 1998).
- 3.3 Certificate of Designations, Preferences, Limitations and Relative Rights of The Series a Junior Participating Preferred Stock of PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit A of the Rights Agreement attached as Exhibit 1 to Form 8-A filed November 9, 2001).
- 3.4 Certificate of Designations establishing the 6.875% Series B Cumulative Convertible Perpetual Preferred Stock, dated September 24, 2007 (incorporated herein by reference to Exhibit 3.1 to Form 8-K filed on September 24, 2007).
- 3.5 Certificate of Amendment to Certificate of Incorporation dated May 14, 2008 (incorporated herein by reference to Exhibit 3.1 to Form 8-K filed June 23, 2009).
- 3.6 Certificate of Amendment to Certificate of Incorporation dated May 18, 2016 (incorporated herein by reference to Exhibit 3.1 to Form 8-K filed on May 20, 2016).
- 3.7 Certificate of Amendment to Certificate of Incorporation dated May 18, 2016 (incorporated herein by reference to Exhibit 3.2 to Form 8-K filed on May 20, 2016).
- 3.8 Bylaws of PetroQuest Energy, Inc., as amended of February 19, 2016 (incorporated herein by reference to Exhibit 3.1 to Form 8-K filed February 22, 2016).
- 4.1 Indenture, dated August 19, 2010, between PetroQuest Energy, Inc. and The Bank of New York Mellon Trust Company, N.A. (incorporated herein by reference to Exhibit 4.2 to Form 8-K filed on August 19, 2010).

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- 4.2 First Supplemental Indenture, dated August 19, 2010, among PetroQuest Energy, Inc., the Subsidiary Guarantors identified therein, and The Bank of New York Mellon Trust Company, N.A. (incorporated herein by reference to Exhibit 4.3 to Form 8-K filed on August 19, 2010).
- 4.3 Second Supplemental Indenture, dated July 3, 2013, among PetroQuest Energy, Inc., the Subsidiary Guarantors identified therein, and The Bank of New York Mellon Trust Company, N.A. (incorporated herein by reference to Exhibit 4.2 to Form 8-K filed on July 3, 2013).
- 4.4 Third Supplemental Indenture, dated October 23, 2013, among PetroQuest Energy, Inc., the Subsidiary Guarantors identified therein, and The Bank of New York Mellon Trust Company, N.A. (incorporated herein by reference to Exhibit 4.7 to Form 10-K filed on March 6, 2015).
- 4.5 Fourth Supplemental Indenture, dated February 1, 2015, among PetroQuest Energy, Inc., the Subsidiary Guarantors identified therein, and U.S. Bank National Association, as successor trustee to The Bank of New York Mellon Trust Company, N.A. (incorporated herein by reference to Exhibit 4.1 to Form 8-K filed on February 3, 2016).
- 4.6 Registration Rights Agreement, dated February 17, 2016, among PetroQuest Energy, Inc., the Subsidiary Guarantors identified therein, and Seaport Global Securities LLC, as representative of the several investors named therein (incorporated herein by reference to Exhibit 4.2 to Form 8-K filed on February 18, 2016).
- 4.7 Indenture, dated February 17, 2016, between PetroQuest Energy, Inc., the Subsidiary Guarantors identified therein, and Wilmington Trust, National Association (incorporated herein by reference to Exhibit 4.1 to Form 8-K filed on February 18, 2016).
- 4.8 First Supplemental Indenture, dated as of September 13, 2016, among PetroQuest Energy, Inc., the Subsidiary Guarantors identified therein, and Wilmington Trust, National Association (incorporated herein by reference to Exhibit 4.1 to Form 8-K filed on September 14, 2016).
- 4.9 Registration Rights Agreement, dated July 3, 2013, among PetroQuest Energy, Inc., the Subsidiary Guarantors identified therein, and J.P. Morgan Securities LLC, as representative of the several initial purchasers named therein (incorporated herein by reference to Exhibit 4.3 to Form 8-K filed on July 3, 2013).
- 4.10 Waiver of Registration Rights, dated as of September 13, 2016, among PetroQuest Energy, Inc., the Subsidiary Guarantors and Seaport Global Securities LLC (incorporated herein by reference to Exhibit 4.2 to Form 8-K filed on September 14, 2016).
- 4.11 Indenture, dated September 27, 2016, among PetroQuest Energy, Inc., the Subsidiary Guarantors identified therein, and Wilmington Trust, National Association (incorporated herein by reference to Exhibit 4.1 to Form 8-K filed on September 27, 2016).
- 4.12 Registration Rights Agreement, dated September 27, 2016, among PetroQuest Energy, Inc., the Subsidiary Guarantors identified therein, Jefferies LLC and Seaport Global Securities LLC (incorporated herein by reference to Exhibit 4.2 to Form 8-K filed on September 27, 2016).
- †10.1 PetroQuest Energy, Inc. 1998 Incentive Plan, as amended and restated effective May 14, 2008 (the “Incentive Plan”) (incorporated herein by reference to Appendix A of the Proxy Statement on Schedule 14A filed April 9, 2008).
- †10.2 Form of Incentive Stock Option Agreement for executive officers (including Charles T. Goodson, Arthur M. Mixon, III, J. Bond Clement and Edward E. Abels, Jr.) under the PetroQuest Energy, Inc. 1998 Incentive Plan (incorporated herein by reference to Exhibit 10.2 to Form 10-K filed February 27, 2009).
- †10.3 Form of Nonstatutory Stock Option Agreement under the PetroQuest Energy, Inc. 1998 Incentive Plan (incorporated herein by reference to Exhibit 10.3 to Form 10-K filed February 27, 2009).

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- †10.4 Form of Restricted Stock Agreement for executive officers (including Charles T. Goodson, Arthur M. Mixon, III, J. Bond Clement and Edward E. Abels, Jr.) under the PetroQuest Energy, Inc. 1998 Incentive Plan (incorporated herein by reference to Exhibit 10.4 to Form 10-K filed February 27, 2009).
- †10.5 PetroQuest Energy, Inc. Annual Incentive Plan (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed on May 13, 2010).
- †10.6 PetroQuest Energy, Inc. Annual Incentive Plan, as amended and restated (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed on June 8, 2010).
- †10.7 PetroQuest Energy, Inc. 2012 Employee Stock Purchase Plan (incorporated herein by reference to Appendix A to Schedule 14A filed March 28, 2012).
- †10.8 PetroQuest Energy, Inc. Long-Term Cash Incentive Plan (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed November 15, 2012).
- †10.9 PetroQuest Energy, Inc. 2013 Incentive Plan (incorporated herein by reference to Appendix A to the Company's Definitive Proxy Statement on Schedule 14A filed on April 9, 2013).
- †10.10 Form of Award Notice of Restricted Stock Units - Employees (including Charles T. Goodson, Arthur M. Mixon, III, J. Bond Clement and Edward E. Abels, Jr.) under the PetroQuest Energy, Inc. Long-Term Cash Incentive Plan (incorporated herein by reference to Exhibit 10.2 to Form 8-K filed November 15, 2012).
- †10.11 Form of Award Notice of Restricted Stock Units - Outside Director/Consultant under the PetroQuest Energy, Inc. Long-Term Cash Incentive Plan (incorporated herein by reference to Exhibit 10.3 to Form 8-K filed November 15, 2012).
- †10.12 Form of Restricted Stock Agreement - Executive Officers (including Charles T. Goodson, Arthur M. Mixon, III, J. Bond Clement and Edward E. Abels, Jr.) under the PetroQuest Energy, Inc. 1998 Incentive Plan (incorporated herein by reference to Exhibit 10.4 to Form 8-K filed November 15, 2012).
- †10.13 Form of Restricted Stock Units Agreement - Employees (including Charles T. Goodson, Arthur M. Mixon, III, J. Bond Clement and Edward E. Abels, Jr.) under the PetroQuest Energy, Inc. 2013 Incentive Plan (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed November 19, 2014).
- †10.14 Form of Award Notice of Phantom Stock Units - Employees (including Charles T. Goodson, Arthur M. Mixon, III, J. Bond Clement and Edward E. Abels, Jr.) under the PetroQuest Energy, Inc. Long-Term Cash Incentive Plan (incorporated herein by reference to Exhibit 10.2 to Form 8-K filed November 19, 2014).
- †10.15 Form of Performance Unit Notice and Award- Employees (including Charles T. Goodson, Arthur M. Mixon, III, J. Bond Clement and Edward E. Abels, Jr.) under the PetroQuest Energy, Inc. Long-Term Cash Incentive Plan (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed November 21, 2014).
- 10.16 Multidraw Term Loan Agreement, dated as of October 17, 2016, among PetroQuest Energy, Inc., PetroQuest Energy, L.L.C., Franklin Custodian Funds - Franklin Income Fund, and Wells Fargo Bank, National Association, as administrative agent (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed on October 17, 2016).
- †10.17 Amended Executive Employment Agreement dated effective as of December 31, 2008, between Charles T. Goodson and PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed January 6, 2009).
- †10.18 Amended Executive Employment Agreement dated effective as of December 31, 2008, between Arthur M. Mixon, III and PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit 10.3 to Form 8-K filed January 6, 2009).

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- †10.19 Amended Executive Employment Agreement dated effective as of December 31, 2008, between J. Bond Clement and PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit 10.20 to Form 10-K filed February 27, 2009).
- †10.20 Executive Employment Agreement dated February 1, 2014 between PetroQuest Energy, Inc. and Edward E. Abels, Jr. (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed February 5, 2014).
- †10.21 Form of Amended Termination Agreement between the Company and each of its executive officers, including Charles T. Goodson, Arthur M. Mixon, III, and J. Bond Clement (incorporated herein by reference to Exhibit 10.6 to Form 8-K filed January 6, 2009).
- †10.22 Termination Agreement dated February 1, 2014 between PetroQuest Energy, Inc. and Edward E. Abels, Jr. (incorporated herein by reference to Exhibit 10.2 to Form 8-K filed February 5, 2014).
- †10.23 Form of Indemnification Agreement between PetroQuest Energy, Inc. and each of its directors and executive officers, including Charles T. Goodson, Arthur M. Mixon, III, J. Bond Clement, Edward E. Abels, Jr., William W. Rucks, IV, E. Wayne Nordberg, J. Gerard Jolly, W.J. Gordon, III and Charles F. Mitchell, II (incorporated herein by reference to Exhibit 10.21 to Form 10-K filed March 13, 2002).
- †10.24 Form of Surrender and Cancellation Agreement for Directors and Executive Officers (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed on September 16, 2010).
- 10.25 Collateral Trust Agreement, dated February 17, 2016, among PetroQuest Energy, Inc., the guarantors from time to time party thereto, Wilmington Trust, National Association, as Trustee, the other Parity Lien Debt Representatives from time to time party thereto and Wilmington Trust, National Association, as Collateral Trustee (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed on February 18, 2016).
- 10.26 Intercreditor Agreement, dated February 17, 2016, by and between JPMorgan Chase Bank, N.A., as Priority Lien Agent, and Wilmington Trust, National Association, as Second Lien Collateral Trustee (incorporated herein by reference to Exhibit 10.2 to Form 8-K filed on February 18, 2016).
- +10.27 PetroQuest Energy, Inc. 2016 Long Term Incentive Plan (incorporated herein by reference to Appendix A to the Company's Definitive Proxy Statement on Schedule 14A filed on April 7, 2016).
- 14.1 Code of Business Conduct and Ethics (incorporated herein by reference to Exhibit 14.1 to Form 10-K filed March 8, 2006).
- \*21.1 Subsidiaries of the Company.
- \*23.1 Consent of Independent Registered Public Accounting Firm.
- \*23.2 Consent of Ryder Scott Company, L.P.
- \*31.1 Certification of Chief Executive Officer pursuant to Rule 13-a-14(a) / Rule 15d-14(a), promulgated under the Securities Exchange Act of 1934, as amended.
- \*31.2 Certification of Chief Financial Officer pursuant to Rule 13-a-14(a) / Rule 15d-14(a), promulgated under the Securities Exchange Act of 1934, as amended.
- \*32.1 Certification pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, of Chief Executive Officer.
- \*32.2 Certification pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, of Chief Financial Officer.
- \*99.1 Reserve report letter as of December 31, 2016, as prepared by Ryder Scott Company, L.P.

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101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Definitions Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

\* Filed herewith.

\*\* The registrant agrees to furnish supplementally a copy of any omitted schedule to the Agreements to the SEC upon request.

† Management contract or compensatory plan or arrangement

# Confidential treatment has been granted for portions of this exhibit. Omissions are designated with brackets containing asterisks. As part of our confidential treatment request, a complete version of this exhibit was filed separately with the SEC.

(b) Exhibits. See Item 15 (a) (3) above.

(c) Financial Statement Schedules. None

Item 16. **10K-Summary**

NONE

### GLOSSARY OF CERTAIN OIL AND NATURAL GAS TERMS

The following is a description of the meanings of some of the oil and natural gas used in this Form 10-K.

*Bbl.* One stock tank barrel, or 42 U.S. gallons liquid volume, of crude oil or other liquid hydrocarbons.

*Bcf.* Billion cubic feet of natural gas.

*Bcfe.* Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

*Block.* A block depicted on the Outer Continental Shelf Leasing and Official Protraction Diagrams issued by the U.S. Minerals Management Service or a similar depiction on official protraction or similar diagrams issued by a state bordering on the Gulf of Mexico.

*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 the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

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

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

*Developed acreage.* The number of acres that are allocated or assignable to productive wells or wells capable of production.

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

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

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

*Farm-in or farm-out.* An agreement under which the owner of a working interest in a natural gas and oil lease assigns the working interest or a portion of the working interest to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a "farm-in" while the interest transferred by the assignor is a "farm-out."

*Field.* An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

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

*Lead.* A specific geographic area which, based on supporting geological, geophysical or other data, is deemed to have potential for the discovery of commercial hydrocarbons.

*MBbls.* Thousand barrels of crude oil or other liquid hydrocarbons.

*Mcf.* Thousand cubic feet of natural gas.

*Mcfe.* Thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

*MMBls.* Million barrels of crude oil or other liquid hydrocarbons.

*MMBtu.* Million British Thermal Units.

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*MMcf.* Million cubic feet of natural gas.

*MMcfe.* Million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

*Ngl.* Natural gas liquid.

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

*Possible reserves.* Those additional reserves that are less certain to be recovered than probable reserves.

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

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

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

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

*Proved oil and gas reserves.* 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.

*Proved properties.* Properties with proved reserves.

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

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

*Reserves.* Estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations.

*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.

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

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

*Stratigraphic test well.* A drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production.



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*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.

*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 natural gas and oil regardless of whether such acreage contains proved reserves.

*Unproved properties.* Properties with no proved reserves

*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.



**INDEX TO FINANCIAL STATEMENTS**

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**Report of Independent Registered Public Accounting Firm**

The Board of Directors and Stockholders  
PetroQuest Energy, Inc.

We have audited the accompanying consolidated balance sheets of PetroQuest Energy, Inc. as of December 31, 2016 and 2015, and the related consolidated statements of operations, comprehensive income (loss), cash flows and stockholders' equity for each of the three years in the period ended December 31, 2016. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the 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 financial statements referred to above present fairly, in all material respects, the consolidated financial position of PetroQuest Energy, Inc. at December 31, 2016 and 2015, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2016, in conformity with U.S. generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), PetroQuest Energy, Inc.'s internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated March 9, 2017 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

New Orleans, Louisiana  
March 9, 2017

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**PETROQUEST ENERGY, INC.**

## Consolidated Balance Sheets

(Amounts in Thousands)

	December 31, 2016	December 31, 2015
<b>ASSETS</b>		
<b>Current assets:</b>		
Cash and cash equivalents	\$ 28,312	\$ 148,013
Revenue receivable	10,294	6,476
Joint interest billing receivable	7,632	49,374
Derivative asset	—	1,508
Other current assets	2,353	3,874
<b>Total current assets</b>	<b>48,591</b>	<b>209,245</b>
<b>Property and equipment:</b>		
<b>Oil and gas properties:</b>		
Oil and gas properties, full cost method	1,323,333	1,310,891
Unevaluated oil and gas properties	9,015	12,516
Accumulated depreciation, depletion and amortization	(1,243,286)	(1,157,455)
<b>Oil and gas properties, net</b>	<b>89,062</b>	<b>165,952</b>
Other property and equipment	10,951	11,229
Accumulated depreciation of other property and equipment	(10,109)	(8,737)
<b>Total property and equipment</b>	<b>89,904</b>	<b>168,444</b>
Other assets, net of accumulated amortization of \$4,385 and \$3,842, respectively	6,365	1,630
<b>Total assets</b>	<b>\$ 144,860</b>	<b>\$ 379,319</b>
<b>LIABILITIES AND STOCKHOLDERS' EQUITY</b>		
<b>Current liabilities:</b>		
Accounts payable to vendors	\$ 25,265	\$ 97,999
Advances from co-owners	2,330	16,118
Oil and gas revenue payable	22,146	18,911
Accrued interest and preferred stock dividend	2,047	12,795
Asset retirement obligation	4,160	6,015
Derivative liability	3,947	—
10% Senior Unsecured Notes due 2017	22,568	—
Other accrued liabilities	3,938	6,946
<b>Total current liabilities</b>	<b>86,401</b>	<b>158,784</b>
Multi-draw Term Loan	7,249	—
10% Senior Unsecured Notes due 2017	—	347,008
10% Senior Secured Notes due 2021	15,228	—
10% Senior Secured PIK Notes due 2021	248,600	—
Asset retirement obligation	32,450	36,541
Other long-term liabilities	6,027	53
<b>Commitments and contingencies</b>		
<b>Stockholders' equity:</b>		
Preferred stock, \$.001 par value; authorized 5,000 shares; issued and outstanding 1,495 shares	1	1
Common stock, \$.001 par value; authorized 150,000 shares; issued and outstanding 21,197 and 16,410 shares, respectively	21	16
Paid-in capital	304,341	290,432
Accumulated other comprehensive income (loss)	(4,750)	947
Accumulated deficit	(550,708)	(454,463)
<b>Total stockholders' equity</b>	<b>(251,095)</b>	<b>(163,067)</b>
<b>Total liabilities and stockholders' equity</b>	<b>\$ 144,860</b>	<b>\$ 379,319</b>

See accompanying Notes to Consolidated Financial Statements.

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**PETROQUEST ENERGY, INC.**  
**Consolidated Statements of Operations**  
 (Amounts in Thousands, Except Per Share Data)

	Year Ended December 31,		
	2016	2015	2014
<b>Revenues:</b>			
Oil and gas sales	\$ 66,667	\$ 115,969	\$ 225,021
<b>Expenses:</b>			
Lease operating expenses	28,508	40,130	48,597
Production taxes	354	2,470	5,927
Depreciation, depletion and amortization	28,720	63,497	87,818
Ceiling test write-down	40,304	266,562	—
General and administrative	26,040	20,777	22,870
Accretion of asset retirement obligation	2,515	3,259	2,958
Interest expense	30,019	33,766	29,281
	<u>156,460</u>	<u>430,461</u>	<u>197,451</u>
<b>Other income (expense):</b>			
Gain on sale of assets	—	21,937	—
Other income (expense)	(560)	391	679
	<u>(560)</u>	<u>22,328</u>	<u>679</u>
Income (loss) from operations	(90,353)	(292,164)	28,249
Income tax expense (benefit)	543	2,626	(2,941)
Net income (loss)	(90,896)	(294,790)	31,190
Preferred stock dividend	5,349	5,139	5,139
Net income (loss) available to common stockholders	<u>\$ (96,245)</u>	<u>\$ (299,929)</u>	<u>\$ 26,051</u>
<b>Earnings (loss) per common share:</b>			
<b>Basic</b>			
Net income (loss) per share	<u>\$ (5.24)</u>	<u>\$ (18.45)</u>	<u>\$ 1.57</u>
<b>Diluted</b>			
Net income (loss) per share	<u>\$ (5.24)</u>	<u>\$ (18.45)</u>	<u>\$ 1.57</u>
<b>Weighted average number of common shares:</b>			
Basic	<u>18,354</u>	<u>16,256</u>	<u>16,051</u>
Diluted	<u>18,354</u>	<u>16,256</u>	<u>16,056</u>

See accompanying Notes to Consolidated Financial Statements.

**PETROQUEST ENERGY, INC.**  
 Consolidated Statements of Comprehensive Income (Loss)  
 (Amounts in Thousands)

	Year Ended		
	December 31,		
	2016	2015	2014
Net income (loss)	\$ (90,896)	\$ (294,790)	\$ 31,190
Change in fair value of derivatives, net of income tax (expense) benefit of \$561, \$2,650 and (\$3,211) respectively	(5,697)	(4,473)	6,516
Comprehensive income (loss)	<u>\$ (96,593)</u>	<u>\$ (299,263)</u>	<u>\$ 37,706</u>

See accompanying Notes to Consolidated Financial Statements.

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PETROQUEST ENERGY, INC.  
Consolidated Statements of Cash Flows  
(Amounts in Thousands)

	Year Ended		
	December 31,		
	2016	2015	2014
<b>Cash flows provided by (used in) operating activities:</b>			
Net income (loss)	\$ (90,896)	\$ (294,790)	\$ 31,190
<b>Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:</b>			
Deferred tax expense (benefit)	543	2,626	(2,941)
Depreciation, depletion and amortization	28,720	63,497	87,818
Ceiling test writedown	40,304	266,562	—
Accretion of asset retirement obligation	2,515	3,259	2,958
Share based compensation expense	1,444	4,617	5,248
Gain on sale of assets	—	(21,937)	—
Amortization costs and other	2,106	2,259	2,188
Non-cash PIK interest	5,722	—	—
Payments to settle asset retirement obligations	(3,169)	(2,776)	(3,623)
Costs incurred to issue 2021 Notes and 2021 PIK Notes	10,139	—	—
<b>Changes in working capital accounts:</b>			
Revenue receivable	(3,818)	10,009	10,083
Joint interest billing receivable	41,400	223	(20,276)
Accounts payable and accrued liabilities	(72,760)	(9,400)	50,243
Advances from co-owners	(13,788)	3,299	11,850
Other	(5,060)	2,657	3,470
Net cash provided by (used in) operating activities	<u>(56,598)</u>	<u>30,105</u>	<u>178,208</u>
<b>Cash flows provided by (used in) investing activities:</b>			
Investment in oil and gas properties	(30,366)	(90,218)	(174,633)
Investment in other property and equipment	(24)	(454)	(926)
Sale of oil and gas properties	25,482	271,769	11,908
Net cash provided by (used in) investing activities	<u>(4,908)</u>	<u>181,097</u>	<u>(163,651)</u>
<b>Cash flows used in financing activities:</b>			
Net payments for share based compensation	11	(199)	(75)
Deferred financing costs	(3,156)	(1,094)	(253)
Payment of preferred stock dividend	(1,285)	(5,139)	(5,139)
Proceeds from borrowings	10,000	70,000	17,500
Repayment of borrowings	—	(145,000)	(17,500)
Redemption of 2017 Notes	(53,626)	—	—
Costs incurred to issue 2021 Notes and 2021 PIK Notes	(10,139)	—	—
Net cash used in financing activities	<u>(58,195)</u>	<u>(81,432)</u>	<u>(5,467)</u>
Net increase (decrease) in cash and cash equivalents	(119,701)	129,770	9,090
Cash and cash equivalents, beginning of period	148,013	18,243	9,153
Cash and cash equivalents, end of period	<u>\$ 28,312</u>	<u>\$ 148,013</u>	<u>\$ 18,243</u>
<b>Supplemental disclosure of cash flow information:</b>			
<b>Cash paid during the period for:</b>			
Interest	<u>\$ 33,206</u>	<u>\$ 36,217</u>	<u>\$ 37,174</u>
Income taxes	<u>\$ (18)</u>	<u>\$ —</u>	<u>\$ 270</u>

See accompanying Notes to Consolidated Financial Statements.



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**PetroQuest Energy Inc.**  
Consolidated Statements of Stockholders' Equity  
*(Amounts in Thousands)*

	Common Stock	Preferred Stock	Paid-In Capital	Other Comprehensive Income (Loss)	Accumulated Deficit	Total Stockholders' Equity
December 31, 2013	\$ 16	\$ 1	\$ 280,759	\$ (1,096)	\$ (180,585)	\$ 99,095
Options exercised	—	—	1,032	—	—	1,032
Retirement of shares upon vesting of restricted stock	—	—	(1,309)	—	—	(1,309)
Share-based compensation expense	—	—	5,248	—	—	5,248
Issuance of shares under employee stock purchase plan	—	—	276	—	—	276
Derivative fair value adjustment, net of tax	—	—	—	6,516	—	6,516
Preferred stock dividend	—	—	—	—	(5,139)	(5,139)
Net income	—	—	—	—	31,190	31,190
December 31, 2014	\$ 16	\$ 1	\$ 286,006	\$ 5,420	\$ (154,534)	\$ 136,909
Options exercised	—	—	61	—	—	61
Retirement of shares upon vesting of restricted stock	—	—	(451)	—	—	(451)
Share-based compensation expense	—	—	4,617	—	—	4,617
Issuance of shares under employee stock purchase plan	—	—	199	—	—	199
Derivative fair value adjustment, net of tax	—	—	—	(4,473)	—	(4,473)
Preferred stock dividend	—	—	—	—	(5,139)	(5,139)
Net loss	—	—	—	—	(294,790)	(294,790)
December 31, 2015	\$ 16	\$ 1	\$ 290,432	\$ 947	\$ (454,463)	\$ (163,067)
Issuance of shares in debt exchange	5	—	12,520	—	—	12,525
Retirement of shares upon vesting of restricted stock	—	—	(200)	—	—	(200)
Share-based compensation expense	—	—	1,444	—	—	1,444
Issuance of shares under employee stock purchase plan	—	—	145	—	—	145
Derivative fair value adjustment, net of tax	—	—	—	(5,697)	—	(5,697)
Preferred stock dividend	—	—	—	—	(5,349)	(5,349)
Net loss	—	—	—	—	(90,896)	(90,896)
December 31, 2016	\$ 21	\$ 1	\$ 304,341	\$ (4,750)	\$ (550,708)	\$ (251,095)

See accompanying Notes to Consolidated Financial Statements.

### PETROQUEST ENERGY, INC. NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

#### **Note 1—Organization and Summary of Significant Accounting Policies**

PetroQuest Energy, Inc. (a Delaware Corporation) (“PetroQuest”) is an independent oil and gas company headquartered in Lafayette, Louisiana with an exploration office in The Woodlands, Texas. It is engaged in the exploration, development, acquisition and operation of oil and gas properties in Texas and the Gulf Coast Basin.

##### Principles of Consolidation

The consolidated financial statements include the accounts of PetroQuest and its subsidiaries, PetroQuest Energy, L.L.C., PetroQuest Oil & Gas, L.L.C, Pittrans, Inc. and TDC Energy LLC (collectively, the "Company"). All intercompany accounts and transactions have been eliminated. Certain prior period amounts have been reclassified to conform to current year presentation.

##### Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Estimates of proved oil and gas reserves and future net cash flows from estimated proved reserves are based on geological and engineering data and depend upon a number of variable factors and assumptions. Changes in estimated proved oil and gas reserves used in the calculation of depreciation, depletion and amortization of oil and gas properties or the present value of the estimated future net cash flows from estimated proved reserves used in the ceiling test could have a material impact on future results of operations.

##### Oil and Gas Properties

The Company utilizes the full cost method of accounting, which involves capitalizing all acquisition, exploration and development costs incurred for the purpose of finding oil and gas reserves including the costs of drilling and equipping productive wells, dry hole costs, lease acquisition costs and delay rentals. The Company also capitalizes the portion of general and administrative costs that can be directly identified with acquisition, exploration or development of oil and gas properties. Unevaluated property costs are transferred to evaluated property costs at such time as wells are completed on the properties, the properties are sold, or management determines these costs to have been impaired. Interest is capitalized on unevaluated property costs. Transactions involving sales of reserves in place are recorded as adjustments to accumulated depreciation, depletion and amortization with no gain or loss recognized, unless such adjustments would cause a significant alteration in the relationship between capitalized costs and proved reserves.

Depreciation, depletion and amortization of oil and gas properties is computed using the unit-of-production method based on estimated proved reserves. All costs associated with evaluated oil and gas properties, including an estimate of future development costs associated therewith, are included in the depreciable base. The costs of investments in unevaluated properties are excluded from this calculation until the related properties are evaluated, proved reserves are established or the properties are determined to be impaired. Proved oil and gas reserves are estimated annually by independent petroleum engineers.

The capitalized costs of proved oil and gas properties cannot exceed the present value of the estimated net future cash flows from proved reserves based on historical twelve-month, first day of the month, average oil, gas and natural gas liquid prices, including the effect of hedges in place (the full cost ceiling). If the capitalized costs of proved oil and gas properties exceed the full cost ceiling, the Company is required to write-down the value of its oil and gas properties to the full cost ceiling amount. The Company follows the provisions of Staff Accounting Bulletin (“SAB”) No. 106, regarding the application of Accounting Standards Codification (“ASC”) Topic 410-20 by companies following the full cost accounting method. SAB No. 106 indicates that estimated future dismantlement and abandonment costs that are recorded on the balance sheet are to be included in the costs subject to the full cost ceiling limitation. The estimated future cash outflows associated with settling the recorded asset retirement obligations are excluded from the computation of the present value of estimated future net revenues used in applying the ceiling test.

##### Cash and Cash Equivalents

The Company considers all highly liquid investments with a stated maturity of three months or less to be cash and cash equivalents. The majority of the Company’s cash and cash equivalents are in overnight securities made through its commercial bank accounts, which result in available funds the next business day.

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### Accounts Receivable

In its capacity as operator, the Company incurs drilling and operating costs that are billed to its partners based on their respective working interests.

### Other Property and Equipment

The costs related to other furniture and fixtures are depreciated on a straight line basis over estimated useful lives ranging from three to eight years.

### Other Assets

Other assets at December 31, 2016 included \$6.2 million related to cash collateral paid with respect to the Company's surety bonds which secure its offshore decommissioning obligations. Other assets at December 31, 2015 included \$1.4 million related to deferred financing costs with respect to the Company's bank credit facility, which were written off upon termination of the bank credit facility.

### Income Taxes

The Company accounts for income taxes in accordance with ASC Topic 740. Provisions for income taxes include deferred taxes resulting primarily from temporary differences due to different reporting methods for oil and gas properties for financial reporting purposes and income tax purposes. For financial reporting purposes, all exploratory and development expenditures are capitalized and depreciated, depleted and amortized on the unit-of-production method. For income tax purposes, only the equipment and leasehold costs relative to successful wells are capitalized and recovered through depreciation or depletion. Generally, most other exploratory and development costs are charged to expense as incurred; however, the Company may use certain provisions of the Internal Revenue Code that allow capitalization of intangible drilling costs. Other financial and income tax reporting differences occur primarily as a result of statutory depletion. Deferred tax assets are assessed for realizability and a valuation allowance is established for any portion of the asset for which it is more likely than not will not be realized.

### Revenue Recognition

The Company records natural gas and oil revenue under the sales method of accounting. Under the sales method, the Company recognizes revenues based on the amount of natural gas or oil sold to purchasers, which may differ from the amounts to which the Company is entitled based on its interest in the properties.

### Concentrations

The Company's production is sold on month to month contracts at prevailing prices. The Company attempts to diversify its sales among multiple purchasers and obtain credit protection such as letters of credit and parental guarantees when necessary.

The following table identifies customers from whom the Company derived 10% or more of its oil and gas revenues during the years presented. Based on the availability of other customers, the Company does not believe the loss of any of these customers would have a significant effect on its business or financial condition.

	Year Ended December 31,		
	2016	2015	2014
Shell Trading Co	23%	18%	30%
Laclede Energy Resources	17%	21%	24%
Superior Natural Gas	14%	(a)	(a)
BG Group	10%	10%	(a)
Unimark, LLC	(a)	17%	14%

(a) Less than 10 percent

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### Derivative Instruments

Under ASC Topic 815, the nature of a derivative instrument must be evaluated to determine if it qualifies for hedge accounting treatment. Instruments qualifying for hedge accounting treatment are recorded as an asset or liability measured at fair value and subsequent changes in fair value are recognized in stockholders' equity through other comprehensive income (loss), net of related taxes, to the extent the hedge is effective. If a hedge becomes ineffective because the hedged production does not occur, or the hedge otherwise does not qualify for hedge accounting treatment, the changes in the fair value of the derivative are recorded in the statement of operations as derivative income (expense). The Company does not offset fair value amounts recognized for derivative instruments.

The Company's hedges are specifically referenced to NYMEX prices for natural gas. The effectiveness of hedges is evaluated at the time the contracts are entered into, as well as periodically over the life of the contracts, by analyzing the correlation between NYMEX prices and the posted prices received from the designated production. Through this analysis, the Company is able to determine if a high correlation exists between the prices received for its designated production and the NYMEX prices at which the hedges will be settled. At December 31, 2016, the Company's derivative instruments were designated as effective cash flow hedges. See Note 7 for further discussion of the Company's derivative instruments.

### Recently Issued Accounting Standards

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2014-09, "Revenue from Contracts with Customers" to clarify the principles for recognizing revenue and to develop a common revenue standard and disclosure requirements. The core principle of ASU 2014-09 is that an entity will recognize revenue when it transfers control of goods or services to customers at an amount that reflects the consideration to which it expects to be entitled in exchange for those goods and or services. In August 2015, the FASB issued ASU 2015-14 deferring the effective date of ASU 2014-09 by one year to interim and annual periods beginning on or after December 31, 2017. Entities can choose to apply the standard using either a full retrospective approach or a modified retrospective approach, with the cumulative effect of initially applying ASU 2014-09 recognized at the date of initial application. We expect to apply the modified retrospective approach upon adoption of this standard. The Company is currently evaluating the effect that this new standard will have on its consolidated financial statements and related disclosures, however, the Company does not expect the adoption of the standard will have a material impact on its consolidated financial statements.

In August 2014, the FASB issued ASU 2014-15, "*Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern (Subtopic 205-40)*." The guidance requires management to evaluate whether there are conditions and events that raise substantial doubt about the company's ability to continue as a going concern within one year after the financial statements are issued on both an interim and annual basis. Additionally, management is required to provide certain footnote disclosures if it concludes that substantial doubt exists or when it concludes its plans alleviate substantial doubt about the company's ability to continue as a going concern. ASU 2014-15 became effective for us on December 15, 2016. The standard did not impact the Company's disclosures, financial position, results of operations or cash flows.

In November 2015, the FASB issued ASU 2015-17, "*Balance Sheet Classification of Deferred Taxes*" to simplify the presentation of deferred income taxes. The guidance allows for the presentation of all deferred tax assets and liabilities, along with any related valuation allowance, to be classified as noncurrent on the balance sheet. We early adopted ASU 2015-17, on a retrospective basis, which had no effect on our financial position, results of operations or cash flows.

In February 2016, the FASB issued ASU 2016-02, "*Leases (Topic 842)*" to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The standard is effective for public entities for fiscal years beginning after December 15, 2018, and for interim periods within those fiscal years, with earlier application permitted. Upon adoption the lessee will apply the new standard retrospectively to all periods presented or retrospectively using a cumulative effect adjustment in the year of adoption. The Company is currently evaluating the effect that this new standard may have on our financial statements.

In March 2016, the FASB issued ASU 2016-09, "*Compensation - Stock Compensation (Topic 718)*" to simplify several aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and forfeitures, as well as classification in the statement of cash flows. ASU 2016-09 is effective for public entities for fiscal years beginning after December 15, 2016, and for interim periods within those fiscal years. Early adoption is permitted for any entity in any interim or annual period. An entity that elects early adoption must adopt all of the amendments in ASU 2016-09 in the same period. We are currently evaluating the effect that this new standard may have on our financial statements, but we do not anticipate the implementation of this new standard will have a material effect.

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### Note 2—Acquisitions and Divestitures

#### Divestitures:

On June 4, 2015, the Company completed the sale of a majority of its interests in the Woodford Shale and Mississippian Lime for \$280 million, subject to customary post-closing purchase price adjustments, effective January 1, 2015. At closing, the Company received \$257.7 million in cash and recognized a receivable of \$13.9 million, which was received in full during the third quarter of 2015.

In connection with the sale, the Company entered into a Contract Operating Services Agreement ("COSA") whereby the Company retained a minimal working interest in the assets sold and agreed to provide certain services as a contract operator for the period of one year from the closing date of the sale. The COSA was terminated on November 1, 2016 and the remaining working interest was transferred to the acquiring owner.

At December 31, 2014, the estimated proved reserves attributable to the assets sold totaled approximately 227.2 Bcfe (unaudited), which represented approximately 57% (unaudited) of the Company's estimated proved reserves. Under the full cost method of accounting, sales of oil and gas properties are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless the adjustment significantly alters the relationship between capitalized costs and proved reserves. A significant alteration is generally not expected to occur for sales involving less than 25% of the total proved reserves. If the sale was accounted for as an adjustment of capitalized costs with no gain or loss recognized, the adjustment would have significantly altered the relationship between capitalized costs and proved reserves. Accordingly, the Company recognized a gain on the sale of \$23.2 million during 2015. The carrying value of the properties sold was determined by allocating total capitalized costs within the full cost pool between properties sold and properties retained based on their relative fair values.

In March 2016, the Company sold certain non-producing assets in East Texas for \$7 million to a potential joint venture partner. This sale was accounted for as an adjustment to the capitalized costs of oil and gas properties. After determining it would not pursue a joint venture with this party, the Company repurchased the non-producing assets for \$5 million in December, 2016 as per the terms of the purchase and sale agreement. The Company subsequently entered into a new drilling joint venture in East Texas with another group of partners.

On April 20, 2016, the Company completed the sale of a majority of its remaining Woodford Shale assets in the East Hoss field for approximately \$18 million, subject to customary post-closing purchase price adjustments, effective April 1, 2016. This sale was accounted for as an adjustment to the capitalized costs of oil and gas properties.

On October 31, 2016, the Company completed the sale of its remaining Oklahoma assets for approximately \$0.7 million, subject to customary post-closing purchase-price adjustments, effective November 1, 2016. This sale was accounted for as an adjustment to the capitalized costs of oil and gas properties.

### Note 3—Equity

#### Common Stock

On May 18, 2016, the Company effected a reverse split of the Company's common stock at a ratio of one share of newly issued common stock for each four shares of issued and outstanding common stock (the "Reverse Split"). The purpose of the Reverse Split was to increase the per share trading price of the Company's common stock in order to regain compliance with the New York Stock Exchange continued listing standards. The Reverse Split proportionately reduced the total number of outstanding shares of common stock from approximately 70.5 million shares to approximately 17.6 million shares. All references in the consolidated financial statements and notes to consolidated financial statements to the number of shares, per share data, restricted stock and stock option data have been retroactively adjusted to give effect to the Reverse Split.

#### Convertible Preferred Stock

The Company has 1,495,000 shares of 6.875% Series B Cumulative Convertible Perpetual Preferred Stock (the "Series B Preferred Stock") outstanding.

The following is a summary of certain terms of the Series B Preferred Stock:

*Dividends.* The Series B Preferred Stock accumulates dividends at an annual rate of 6.875% for each share of Series B Preferred Stock. Dividends are cumulative from the date of first issuance and, to the extent payment of dividends is not prohibited by the Company's debt agreements, assets are legally available to pay dividends and the Company's board of directors or an authorized committee of the board declares a dividend payable, the Company pays dividends in cash, every quarter.

In connection with an amendment to the Company's bank credit facility, which was terminated in October, 2016, prohibiting the Company from declaring or paying dividends on the Series B Preferred Stock, the Company suspended the quarterly

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cash dividend on its Series B Preferred Stock beginning with the dividend payment due on April 15, 2016. Under the terms of the Series B Preferred Stock, any unpaid dividends will accumulate. As of December 31, 2016, the Company has deferred three quarterly dividends and has accrued a \$5.1 million payable related to the three deferred quarterly dividends and the quarterly dividend that was payable on January 15, 2017, which is included in other long-term liabilities on the Consolidated Balance Sheet. If the Company fails to pay six quarterly dividends on the Series B Preferred Stock, whether or not consecutive, holders of the Series B Preferred Stock, voting as a single class, will have the right to elect two additional directors to the Company's Board of Directors until all accumulated and unpaid dividends on the Series B Preferred Stock are paid in full. The Multidraw Term Loan Agreement (see Note 9) currently restricts the Company from paying cash dividends on the Series B Preferred Stock.

*Mandatory conversion.* The Company may, at its option, cause shares of the Series B Preferred Stock to be automatically converted at the applicable conversion rate, but only if the closing sale price of the Company's common stock for 20 trading days within a period of 30 consecutive trading days ending on the trading day immediately preceding the date the Company gives the conversion notice equals or exceeds 130% of the conversion price in effect on each such trading day.

*Conversion rights.* Each share of Series B Preferred Stock may be converted at any time, at the option of the holder, into 0.8608 shares of the Company's common stock (which is based on an initial conversion price of approximately \$58.08 per share of common stock, subject to further adjustment) plus cash in lieu of fractional shares, subject to the Company's right to settle all or a portion of any such conversion in cash or shares of the Company's common stock. If the Company elects to settle all or any portion of its conversion obligation in cash, the conversion value and the number of shares of the Company's common stock it will deliver upon conversion (if any) will be based upon a 20 trading day averaging period.

Upon any conversion, the holder will not receive any cash payment representing accumulated and unpaid dividends on the Series B Preferred Stock, whether or not in arrears, except in limited circumstances. The conversion rate is equal to \$50 divided by the conversion price at the time. The conversion price is subject to adjustment upon the occurrence of certain events. The conversion price on the conversion date and the number of shares of the Company's common stock, as applicable, to be delivered upon conversion may be adjusted if certain events occur.

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### Note 4—Earnings Per Share

A reconciliation between the basic and diluted earnings per share computations (in thousands, except per share amounts) is as follows:

<b>For the Year Ended December 31, 2016</b>	<b>Loss(Numerator)</b>	<b>Shares (Denominator)</b>	<b>Per Share Amount</b>
<b>BASIC EPS</b>			
Net loss available to common stockholders	\$ (96,245)	18,354	\$ (5.24)
Stock options	—	—	
Attributable to participating securities	—	—	
<b>DILUTED EPS</b>	<b>\$ (96,245)</b>	<b>18,354</b>	<b>\$ (5.24)</b>
<b>For the Year Ended December 31, 2015</b>			
	<b>Loss(Numerator)</b>	<b>Shares (Denominator)</b>	<b>Per Share Amount</b>
<b>BASIC EPS</b>			
Net loss available to common stockholders	\$ (299,929)	16,256	\$ (18.45)
Stock options	—	—	
Attributable to participating securities	—	—	
<b>DILUTED EPS</b>	<b>\$ (299,929)</b>	<b>16,256</b>	<b>\$ (18.45)</b>
<b>For the Year Ended December 31, 2014</b>			
	<b>Income (Numerator)</b>	<b>Shares (Denominator)</b>	<b>Per Share Amount</b>
Net income available to common stockholders	\$ 26,051	16,051	
Attributable to participating securities	(855)	—	
<b>BASIC EPS</b>	<b>\$ 25,196</b>	<b>16,051</b>	<b>\$ 1.57</b>
Net income available to common stockholders	\$ 26,051	16,051	
<b>Effect of dilutive securities:</b>			
Stock options	—	5	
Attributable to participating securities	(854)	—	
<b>DILUTED EPS</b>	<b>\$ 25,197</b>	<b>16,056</b>	<b>\$ 1.57</b>

An aggregate of 0.9 million shares of common stock representing options to purchase common stock and unvested shares of restricted common stock and common shares issuable upon the assumed conversion of the Series B Preferred Stock totaling 1.3 million shares were not included in the computation of diluted earnings per share for the year ended December 31, 2016, because the inclusion would have been anti-dilutive as a result of the net loss reported for the year.

An aggregate of 0.1 million shares of common stock representing options to purchase common stock and unvested shares of restricted common stock and common shares issuable upon the assumed conversion of the Series B Preferred Stock totaling 1.3 million shares were not included in the computation of diluted earnings per share during the year ended December 31, 2015, because the inclusion would have been anti-dilutive as a result of the net loss reported for the year.

Common shares issuable upon the assumed conversion of the Series B Preferred Stock totaling 1.3 million shares during the year ended December 31, 2014 were not included in the computation of diluted earnings per share because the inclusion would have been anti-dilutive. Options to purchase 0.3 million shares of common stock were outstanding during the year ended December 31, 2014 and were not included in the computation of diluted earnings per share because the options' exercise prices were in excess of the average market price of the common shares.

**Note 5—Share-Based Compensation**

The Company accounts for share-based compensation in accordance with ASC Topic 718. Share-based compensation cost is recognized over the requisite service period. Compensation cost for awards with graded vesting is recognized using the accelerated attribution method. Share-based compensation cost is reflected as a component of general and administrative expenses. A detail of share-based compensation cost for the years ended December 31, 2016, 2015 and 2014 is as follows (in thousands):

	Year Ended December 31,		
	2016	2015	2014
<b>Stock options:</b>			
Incentive Stock Options (share settled)	\$ 206	\$ 243	\$ 573
Non-Qualified Stock Options (share settled)	164	71	171
Restricted stock (share settled)	1,073	4,303	4,504
Cash settled stock units	244	(439)	3,094
Share-based compensation	<u>\$ 1,687</u>	<u>\$ 4,178</u>	<u>\$ 8,342</u>

During the years ended December 31, 2016 and 2014, the Company capitalized \$0.1 million, and \$1.5 million, respectively, of compensation cost related to cash settled restricted stock units to oil and gas properties. No such amounts were capitalized during the year ended December 31, 2015. During the years ended December 31, 2016, 2015 and 2014, the Company recorded income tax benefits of approximately \$0.5 million, \$1.5 million and \$2.3 million, respectively, related to share-based compensation expense recognized during those periods. Any excess tax benefits from the vesting of restricted stock and the exercise of stock options will not be recognized in paid-in capital until the Company is in a current tax paying position. Presently, all of the Company's income taxes are deferred and the Company has net operating losses available to carryover to future periods. Accordingly, no excess tax benefits have been recognized for any periods presented.

**Share-Based compensation settled in shares**

At December 31, 2016, the Company had \$1.8 million of unrecognized compensation cost related to unvested restricted stock and stock options. This amount will be recognized as compensation expense over a weighted average period of approximately three years.

Stock Options

Stock options may be granted to employees and consultants and generally vest equally over a three-year period. Stock options may also be granted to directors and generally vest one year or less from the date of grant to align with their term on the board. Stock options must be exercised within 10 years of the grant date. The exercise price of each option may not be less than 100% of the fair market value of a share of common stock on the date of grant. Upon a change in control of the Company, all outstanding options become immediately exercisable.

The Company computes the fair value of its stock options using the Black-Scholes option-pricing model assuming a stock option forfeiture rate and expected term based on historical activity and expected volatility computed using historical stock price fluctuations on a weekly basis for a period of time equal to the expected term of the option. Periodically, the Company adjusts compensation expense based on the difference between actual and estimated forfeitures.



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There were no stock options granted in 2015. The following table outlines the assumptions used in computing the fair value of stock options granted during 2016 and 2014:

	Years Ended December 31,	
	2016	2014
Dividend yield	—%	—%
Expected volatility	62.0%-79.99%	79.4% - 80.0%
Risk-free rate	1.255%-2.09%	1.81% - 2.015%
Expected term	6 years	6 years
Forfeiture rate	5.0%	5.0%
Stock options granted (1)	1,168,754	17,359
Wgtd. avg. grant date fair value per share	\$1.96	\$11.36
Fair value of grants (1)	\$2,293,000	\$197,000

(1) Prior to applying estimated forfeiture rate

The following table details stock option activity during the year ended December 31, 2016:

	Number of Options	Wgtd. Avg. Exercise Price	Wgtd. Avg. Remaining Life	Aggregate Intrinsic Value (000's)
Outstanding at beginning of year	340,492	\$ 24.38		
Granted	1,168,754	3.33		
Expired/cancelled/forfeited	(96,306)	22.01		
Exercised	—	—		
Outstanding at end of year	<u>1,412,940</u>	7.13	8.74	\$ 186
Options exercisable at end of year	256,013	\$ 24.11	4.73	\$ —
Options expected to vest	1,355,094	7.29	8.71	\$ 176

The total fair value of stock options that vested during the years ended December 31, 2016, 2015 and 2014 was \$0.4 million, \$0.8 million and \$1.0 million, respectively. The intrinsic value of stock options exercised was immaterial for all periods presented.

The following table summarizes information regarding stock options outstanding at December 31, 2016:

Range of Exercise Price	Options Outstanding 12/31/2016	Wgtd. Avg. Remaining Contractual Life	Wgtd. Avg. Exercise Price	Options Exercisable 12/31/2016	Wgtd. Avg. Exercise Price
\$0.00-\$2.49	66,373	9.20	\$2.37		—
\$2.50-\$3.49	878,833	9.74	\$3.17		—
\$3.50-\$4.99	206,769	9.38	\$4.26		—
\$15.00-\$30.32	260,965	4.77	\$23.94	256,013	\$24.11
	<u>1,412,940</u>	8.74	\$7.13	<u>256,013</u>	\$24.11

### Restricted Stock

The Company computes the fair value of its service based restricted stock using the closing price of the Company's stock at the date of grant, and compensation expense is recognized assuming a 5% estimated forfeiture rate. Restricted stock granted to employees generally vests evenly over a three-year period. Restricted stock granted to directors vests one year or less from the date of grant to align with their term on the board. Upon a change in control of the Company, all outstanding shares of restricted stock will become immediately vested.

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The following table details restricted stock activity during the year ended December 31, 2016:

	Number of Shares	Wgtd. Avg. Fair Value per Share
Outstanding at beginning of year	296,259	\$ 16.32
Granted	—	—
Cancelled/forfeited	(67,672)	16.97
Lapse of restrictions	(150,030)	15.90
Outstanding at December 31, 2016	<u>78,557</u>	<u>\$ 16.57</u>

The weighted average grant date fair value of restricted stock granted during the years ended December 31, 2015 and 2014 was \$5.08 and \$17.28, respectively, per share. No restricted stock was granted in 2016. The total fair value of restricted stock that vested during the years ended December 31, 2016, 2015 and 2014 was \$2.4 million, \$4.7 million and \$5.0 million, respectively. At December 31, 2016, the weighted average remaining life of restricted stock outstanding was approximately one year.

### Share-Based compensation settled in cash

#### Restricted Stock Units

The Company may grant restricted stock units ("RSUs") to employees that vest evenly over a three-year period. Cash payment will be made to employees on each vesting date based upon the Company's closing stock price on that date. Upon change in control of the Company, all of the RSUs will immediately vest. The Company computes the fair value of the RSUs using the closing price of the Company's stock at the end of each period and records a liability based on the percentage of requisite service rendered at the reporting date. During 2016, the Company paid \$0.3 million for 0.1 million RSUs that vested during the period.

#### Market Based Restricted Stock Units

The Company granted 60,767 market based restricted stock units ("MRSUs") to executive officers during November 2014. The executive officers can earn between 0-200% of the MRSUs granted based on the Company's performance versus a defined peer group. The MRSUs vest in one-third increments on each of the first, second and third annual anniversaries starting January 1, 2016. Upon change in control of the Company, all of the MRSUs will immediately vest. The number of MRSUs that ultimately vest is based on the Company's total shareholder return in the last 20 days of the fiscal year in relation to the last 20 days of the previous fiscal year in comparison to a group of 12 selected peer stocks of similar sized companies which operate within the same sector. The performance period ended on December 31, 2015 and executive officers earned 50% of the MRSUs. The MRSUs are cash settled on each vesting date based on the number of MRSUs that vest multiplied by the Company's closing stock price. The Company estimates the fair value of the outstanding MRSUs using a Monte Carlo valuation model and records a liability based on the percentage of requisite service rendered at the reporting date. The Monte Carlo valuation model considers such inputs as the Company's and its peer group's stock prices, a risk-free interest rate, and an estimated volatility for the Company and its peer group. As of December 31, 2016, the Company had a liability for RSUs and MRSUs outstanding in the amount of \$0.1 million based upon the closing stock price at December 31, 2016.

The following table details MRSU and RSU activity during the year ended December 31, 2016:

	<u>MRSU</u>	<u>RSU</u>	<u>Total</u>
Outstanding at beginning of year	25,821	188,337	214,158
Granted	—	—	—
Expired/Cancelled/Forfeited	(2,285)	(44,897)	(47,182)
Vested/Paid	(8,607)	(111,461)	(120,068)
Outstanding at December 31, 2016	<u>14,929</u>	<u>31,979</u>	<u>46,908</u>

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### Note 6—Asset Retirement Obligation

The Company accounts for asset retirement obligations in accordance with ASC Topic 410-20, which requires recording the fair value of an asset retirement obligation associated with tangible long-lived assets in the period incurred. Asset retirement obligations associated with long-lived assets included within the scope of ASC Topic 410-20 are those for which there is a legal obligation to settle under existing or enacted law, statute, written or oral contract or by legal construction under the doctrine of promissory estoppel. The Company has legal obligations to plug, abandon and dismantle existing wells and facilities that it has acquired and constructed.

The following table describes the changes to the Company's asset retirement obligation (in thousands):

	Year Ended December 31,	
	2016	2015
Asset retirement obligation, beginning of period	\$ 42,556	\$ 54,970
Liabilities incurred	—	466
Liabilities settled	(3,296)	(2,776)
Accretion expense	2,515	3,259
Revisions in estimated cash flows	(1,746)	(11,137)
Divestiture of oil and gas properties	(3,419)	(2,226)
Asset retirement obligation, end of period	36,610	42,556
Less: current portion of asset retirement obligation	(4,160)	(6,015)
Long-term asset retirement obligation	\$ 32,450	\$ 36,541

Divestitures of oil and gas properties during 2016 included \$3.3 million as a result of the sale of our remaining Oklahoma assets. Divestitures of oil and gas properties during 2015 included \$1.8 million as a result of the sale of our Woodford Shale and Mississippian Lime assets. The liabilities incurred, revisions in estimated cash flows and divestitures represent non-cash investing activities for purposes of the statement of cash flows.

### Note 7—Derivative Instruments

The Company seeks to reduce its exposure to commodity price volatility by hedging a portion of its production through commodity derivative instruments. When the conditions for hedge accounting are met, the Company may designate its commodity derivatives as cash flow hedges. The changes in fair value of derivative instruments that qualify for hedge accounting treatment are recorded in other comprehensive income (loss) until the hedged oil or natural gas quantities are produced. If a derivative does not qualify for hedge accounting treatment, the changes in the fair value of the derivative are recorded in the statement of operations as derivative income (expense). At December 31, 2016 and 2015, all of the Company's outstanding derivative instruments were designated as cash flow hedges.

Oil and gas sales include additions (reductions) related to the settlement of gas hedges of \$1.8 million, \$15.9 million and (\$4.2) million, Ngl hedges of \$0, \$0.5 million and \$0.3 million, and oil hedges of \$0, \$0.6 million and \$0.9 million, for the years ended December 31, 2016, 2015 and 2014, respectively.

As of December 31, 2016, the Company had entered into the following gas hedge contracts:

Production Period	Instrument Type	Daily Volumes	Weighted Average Price
<b>Natural Gas:</b>			
January 2017 - December 2017	Swap	10,000 Mmbtu	\$3.26
January 2017 - March 2018	Swap	10,000 Mmbtu	\$3.01
April 2017 - March 2018	Swap	10,000 Mmbtu	\$3.40

At December 31, 2016, the Company had recognized a liability of approximately \$4.8 million related to the estimated fair value of these derivative contracts. Based on estimated future commodity prices as of December 31, 2016, the Company would realize a \$2.5 million loss, net of taxes, during the next 12 months. This loss is expected to be reclassified to oil and gas sales based on the schedule of volumes stipulated in the derivative contracts.

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During March 2017, we entered into the following additional hedge contract accounted for as a cash flow hedge:

Production Period	Instrument Type	Daily Volumes	Weighted Average Price
<b>Natural Gas:</b>			
October 2017 - March 2018	Swap	10,000 Mmbtu	\$3.22

### Derivatives designated as hedging instruments:

The following tables reflect the fair value of the Company's effective cash flow hedges in the consolidated financial statements (in thousands):

*Effect of Cash Flow Hedges on the Consolidated Balance Sheet at December 31, 2016 and December 31, 2015:*

Period	Commodity Derivatives	
	Balance Sheet Location	Fair Value
December 31, 2016	Derivative liability	\$ (3,947)
December 31, 2016	Other long-term liabilities	\$ (803)
December 31, 2015	Derivative asset	\$ 1,508

*Effect of Cash Flow Hedges on the Consolidated Statement of Operations for years ended December 31, 2016, 2015 and 2014:*

Instrument	Amount of Gain (Loss) Recognized in Other Comprehensive Income	Location of Gain (Loss) Reclassified into Income	Amount of Gain (Loss) Reclassified into Income
Commodity Derivatives at December 31, 2016	\$ (4,447)	Oil and gas sales	\$ 1,811
Commodity Derivatives at December 31, 2015	\$ 9,991	Oil and gas sales	\$ 17,114
Commodity Derivatives at December 31, 2014	\$ 6,683	Oil and gas sales	\$ (3,044)

### Note 8 - Fair Value Measurements

ASC Topic 820 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date and establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. As presented in the tables below, this hierarchy consists of three broad levels:

- Level 1: valuations consist of unadjusted quoted prices in active markets for identical assets and liabilities and has the highest priority;
- Level 2: valuations rely on quoted prices in markets that are not active or observable inputs over the full term of the asset or liability;
- Level 3: valuations are based on prices or third party or internal valuation models that require inputs that are significant to the fair value measurement and are less observable and thus have the lowest priority.

The Company classifies its commodity derivatives based upon the data used to determine fair value. The Company's derivative instruments at December 31, 2016 and 2015 were in the form of swaps based on NYMEX pricing for natural gas. The fair value of these derivatives is derived using an independent third-party's valuation model that utilizes market-corroborated inputs that are observable over the term of the derivative contract. The Company's fair value calculations also incorporate an estimate of the counterparties' default risk for derivative assets and an estimate of the Company's default risk for derivative liabilities. As a result, the Company designates its commodity derivatives as Level 2 in the fair value hierarchy.

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The following table summarizes the Company's assets (liabilities) that are subject to fair value measurement on a recurring basis as of December 31, 2016 and December 31, 2015 (in thousands):

Instrument	Fair Value Measurements Using		
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
<b>Commodity Derivatives:</b>			
At December 31, 2016	\$ —	\$ (4,750)	\$ —
At December 31, 2015	\$ —	\$ 1,508	\$ —

The fair value of the Company's cash and cash equivalents approximated book value at December 31, 2016 and 2015. The fair value of the Multidraw Term Loan Agreement approximated face value as of December 31, 2016. The fair value of the Company's bank credit facility, which was terminated in October 2016, approximated book value as of December 31, 2015. The fair value of the Company's 2017 Notes, 2021 Notes and 2021 PIK Notes was determined based upon market quotes provided by an independent broker, which represents a Level 2 input. The following table summarizes the fair value of the 2017 Notes, 2021 Notes and 2021 PIK Notes as of December 31, 2016 and 2015, respectively (in thousands).

	Fair Value at 12/31/16	Face Value at 12/31/16	Carrying value at 12/31/16	Fair Value at 12/31/15	Face Value at 12/31/15	Carrying value at 12/31/15
2017 Notes	\$ 21,970	\$ 22,650	\$ 22,568	\$ 238,000	\$ 350,000	\$ 347,008
2021 Notes	12,192	14,177	15,228	—	—	—
2021 PIK Notes	177,732	243,468	248,600	—	—	—
	<u>\$ 211,894</u>	<u>\$ 280,295</u>	<u>\$ 286,396</u>	<u>\$ 238,000</u>	<u>\$ 350,000</u>	<u>\$ 347,008</u>

### Note 9—Long-Term Debt

On August 19, 2010, the Company issued \$150 million in principal amount of its 10% Senior Notes due 2017. On July 3, 2013, the Company issued an additional \$200 million in principal amount of its 10% Senior Notes due 2017 (collectively, the "2017 Notes").

On February 17, 2016, the Company closed a private exchange offer (the "February Exchange") and consent solicitation (the "February Consent Solicitation") to certain eligible holders of its outstanding 2017 Notes. In satisfaction of the tender of \$214.4 million in aggregate principal amount of the 2017 Notes, representing approximately 61% of the then outstanding aggregate principal amount of 2017 Notes, the Company (i) paid approximately \$53.6 million of cash, (ii) issued \$144.7 million aggregate principal amount of its new 10% Second Lien Senior Secured Notes due 2021 (the "2021 Notes") and (iii) issued approximately 1.1 million shares of its common stock. Following the completion of the February Exchange, \$135.6 million in aggregate principal amount of the 2017 Notes remained outstanding. The February Consent Solicitation eliminated or waived substantially all of the restrictive covenants contained in the indenture governing the 2017 Notes.

On September 27, 2016, the Company closed private exchange offers (the "September Exchange") and a consent solicitation (the "September Consent Solicitation") to certain eligible holders of its outstanding 2017 Notes and 2021 Notes. In satisfaction of the consideration of \$113.0 million in aggregate principal amount of the 2017 Notes, representing approximately 83% of the then outstanding aggregate principal amount of 2017 Notes, and \$130.5 million in aggregate principal amount of the 2021 Notes, representing approximately 90% of the then outstanding aggregate principal amount of 2021 Notes, the Company issued (i) \$243.5 million in aggregate principal amount of its new 10% Second Lien Senior Secured PIK Notes due 2021 (the "2021 PIK Notes") and (ii) approximately 3.5 million shares of its common stock. The Company also paid, in cash, accrued and unpaid interest on the 2017 Notes and 2021 Notes accepted in the September Exchange from the last applicable interest payment date to, but not including, September 27, 2016. Following the consummation of the September Exchange, there is \$22.7 million in aggregate principal amount of the 2017 Notes outstanding and \$14.2 million in aggregate principal amount of the 2021 Notes outstanding. The September Consent Solicitation amended certain provisions of the indenture governing the 2021 Notes and amended the registration rights agreement with respect to the 2021 Notes.

Unless the Company exercises its payable in kind ("PIK") interest option, the 2021 PIK Notes bear interest at a rate of 10% per annum on the principal amount and interest is payable semi-annually in arrears on February 15 and August 15 of each year, starting on February 15, 2017. The Company may, at its option, for one or more of the first three interest payment dates of the 2021 PIK Notes, pay interest at (i) the annual rate of 1% in cash plus (ii) the annual rate of 9% PIK (the "PIK Interest") payable

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by increasing the principal amount outstanding of the 2021 PIK Notes or by issuing additional 2021 PIK Notes in certificated form. We exercised this PIK option in connection with the interest payment due on February 15, 2017. As of December 31, 2016, the Company was in compliance with all of the covenants under the 2021 PIK Notes.

The 2021 Notes bear interest at a rate of 10% per annum on the principal amount and interest is payable semi-annually in arrears on February 15 and August 15 of each year. As of December 31, 2016, the Company was in compliance with all of the covenants under the 2021 Notes.

The 2017 Notes bear interest at a rate of 10% per annum on the principal amount and interest is payable semi-annually in arrears on March 1 and September 1 of each year and the 2017 Notes mature on September 1, 2017. As of December 31, 2016, the Company was in compliance with the remaining covenants under the 2017 Notes.

The February Exchange and September Exchange were accounted for as troubled debt restructurings pursuant to ASC Topic 470-60 "Troubled Debt Restructurings by Debtors." The Company determined that the future undiscounted cash flows from the 2021 PIK Notes issued in the September Exchange through the maturity date exceeded the adjusted carrying amount of the 2017 Notes and the 2021 Notes tendered in the September Exchange. Accordingly, no gain or loss on extinguishment of debt was recognized in connection with the September Exchange. The net shortfall of the remaining carrying value of the 2017 Notes and 2021 Notes tendered as compared to the principal amount of the 2021 PIK Notes issued in the September Exchange of \$0.6 million is reflected as part of the carrying value of the 2021 PIK Notes. Such shortfall is being amortized under the effective interest method over the term of the 2021 PIK Notes.

The Company previously determined that the future undiscounted cash flows from the 2021 Notes issued in the February Exchange through the maturity date exceeded the adjusted carrying amount of the 2017 Notes tendered in the February Exchange. Accordingly, no gain on extinguishment of debt was recognized in connection with the February Exchange. The excess of the remaining carrying value of the 2017 Notes tendered over the principal amount of the 2021 Notes issued in the February Exchange of \$13.9 million was reflected as part of the carrying value of the 2021 Notes. The amount of the excess carrying value attributable to the 2021 Notes tendered in the September Exchange is now reflected as part of the carrying value of the 2021 PIK Notes. The excess carrying value attributable to the remaining 2021 Notes is being amortized under the effective interest method over the term of the 2021 Notes. At December 31, 2016, \$1.2 million of the excess remained as part of the carrying value of the 2021 Notes and the Company recognized \$1.5 million of amortization expense as a reduction to interest expense during the year ended December 31, 2016.

The issuance of the 2021 Notes, 2021 PIK Notes and shares of common stock, as well as the exchange of the 2017 Notes and 2021 Notes in the February Exchange and September Exchange represent non-cash financing activities for purposes of the statement of cash flows.

The indentures governing the 2021 PIK Notes and the 2021 Notes contain affirmative and negative covenants that, among other things, limit the ability of the Company and the subsidiary guarantors of the 2021 PIK Notes and the 2021 Notes to incur indebtedness; purchase or redeem stock; make certain investments; create liens that secure debt; enter into transactions with affiliates; sell assets; refinance certain indebtedness; merge with or into other companies or transfer substantially all of their assets; and, in certain circumstances, to pay dividends or make other distributions on stock. The 2021 PIK Notes and the 2021 Notes are fully and unconditionally guaranteed on a senior basis, jointly and severally, by certain wholly-owned subsidiaries of the Company.

The 2021 PIK Notes and the 2021 Notes are secured equally and ratably by second-priority liens on substantially all of the Company's and the subsidiary guarantors' oil and gas properties and substantially all of their other assets to the extent such properties and assets secure the Multidraw Term Loan Agreement (as defined below), except for certain excluded assets. Pursuant to the terms of an intercreditor agreement, the security interest in those properties and assets that secure the 2021 PIK Notes and the 2021 Notes and the guarantees are contractually subordinated to liens that secure the Multidraw Term Loan Agreement and certain other permitted indebtedness. Consequently, the 2021 PIK Notes and the 2021 Notes and the guarantees will be effectively subordinated to the Multidraw Term Loan Agreement and such other indebtedness to the extent of the value of such assets.

On October 17, 2016, the Company entered into the Multidraw Term Loan Agreement (the "Multidraw Term Loan Agreement") with Franklin Custodian Funds - Franklin Income Fund ("Franklin"), as a lender, and Wells Fargo Bank, National Association, as administrative agent, replacing the credit agreement with JPMorgan Chase Bank, N.A. The Multidraw Term Loan Agreement provides a multi-advance term loan facility, with borrowing availability for three years, in a principal amount of up to \$50.0 million. The loans drawn under the Multidraw Term Loan Agreement (collectively, the "Term Loans") may be used to repay existing debt (including the remaining 2017 Notes), to pay transaction fees and expenses, to provide working capital for exploration and production operations and for general corporate purposes. The Term Loans mature on October 17, 2020. As of December 31, 2016, the Company has \$10.0 million of borrowings outstanding under the Term Loans.

The Company's obligations under the Multidraw Term Loan Agreement and the Term Loans are secured by a first priority lien on substantially all of the assets of the Company and certain of its subsidiaries, including a lien on all equipment and at least 90% of the aggregate total value of the oil and gas properties of the Company and its subsidiaries, a pledge of the equity interests of PetroQuest Energy, L.L.C. (the "Borrower") and certain of the Company's other subsidiaries, and corporate guarantees of the

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Company and certain of the Company's other subsidiaries of the indebtedness of the Borrower. Term Loans under the Multidraw Term Loan Agreement bear interest at the rate of 10% per annum.

The Company and its subsidiaries are subject to a restrictive financial covenant under the Multidraw Term Loan Agreement, consisting of maintaining a ratio of (i) the present value, discounted at 10% per annum, of the estimated future net revenues in respect of the Company's and its subsidiaries' oil and gas properties, before any state, federal, foreign or other income taxes, attributable to proved developed reserves, using three-year strip prices in effect at the end of each calendar quarter, including swap agreements in place at the end of each quarter, to (ii) the sum of the outstanding Term Loans and the then outstanding commitments to provide Term Loans, that shall not be less than (a) 1.7 to 1.0 as measured on December 31, 2016 and March 31, 2017, and (b) 2.0 to 1.0 as measured on June 30, 2017, and the last day of each calendar quarter thereafter (the "Coverage Ratio").

Sales of the Company's and its subsidiaries' oil and gas properties outside the ordinary course of business are limited under the terms of the Multidraw Term Loan Agreement. In addition, the Multidraw Term Loan Agreement prohibits the Company from declaring and paying dividends on its Series B Preferred Stock.

The Multidraw Term Loan Agreement also includes customary restrictions with respect to debt, liens, dividends, distributions and redemptions, investments, loans and advances, nature of business, international operations and foreign subsidiaries, leases, sale or discount of receivables, mergers or consolidations, sales of properties, transactions with affiliates, negative pledge agreements, gas imbalances and swap agreements. As of December 31, 2016, no default or event of default existed under the Multidraw Term Loan Agreement and the Company was in compliance with all covenants contained in the Multidraw Term Loan Agreement, including the Coverage Ratio.

The 2017 Notes are reflected net of \$0.1 million and \$3.0 million of related unamortized financing costs at December 31, 2016 and 2015, respectively. The 2021 Notes are reflected net of \$0.1 million of related unamortized financing costs as of December 31, 2016 and the Term Loans are reflected net of \$2.8 million of related unamortized financing costs as of December 31, 2016.

The following table reconciles the face value of the 2017 Notes, 2021 Notes, 2021 PIK Notes and Term Loans to the carrying value included in the consolidated balance sheet as of December 31, 2016 and 2015 (in thousands):

	December 31, 2016				December 31, 2015			
	2017 Notes	2021 Notes	2021 PIK Notes	Term Loans	2017 Notes	2021 Notes	2021 PIK Notes	Term Loans
Face Value	\$ 22,650	\$ 14,177	\$ 243,468	\$ 10,000	\$ 350,000	\$ —	\$ —	\$ —
Unamortized Deferred Financing Costs	(82)	(108)	—	(2,751)	(2,992)	—	—	—
Excess (shortfall) Carrying Value	—	1,159	(590)	—	—	—	—	—
Accrued PIK Interest	—	—	5,722	—	—	—	—	—
Carrying Value	\$ 22,568	\$ 15,228	\$ 248,600	\$ 7,249	\$ 347,008	\$ —	\$ —	\$ —

On March 1, 2017, we notified the holders of the 2017 Notes that we will redeem the remaining \$22.7 million of 2017 Notes on March 31, 2017 at a redemption price of 100% of the principal amount thereof, plus accrued interest to the redemption date. We expect to pay the redemption price with a combination of cash on hand and amounts borrowed under the Multidraw Term Loan Agreement described above.

### Note 10—Related Party Transactions

Two of the Company's senior officers, Charles T. Goodson and Stephen H. Green, or their affiliates, are working interest owners and overriding royalty interest owners and E. Wayne Nordberg and William W. Rucks, IV, two of the Company's directors, are working interest owners in certain properties operated by the Company or in which the Company also holds a working interest. As working interest owners, they are required to pay their proportionate share of all costs and are entitled to receive their proportionate share of revenues in the normal course of business. As overriding royalty interest owners, they are entitled to receive their proportionate share of revenues in the normal course of business.

During 2016, in their capacities as working interest owners or overriding royalty interest owners, revenues, net of costs, were disbursed to (received from) Messrs. Goodson and Green, or their affiliates, in the amounts of \$(15,000) and \$25,000, respectively, and with respect to Mr. Nordberg, costs billed exceeded revenues disbursed in the amount of \$200. During 2015, in their capacities as working interest owners or overriding royalty interest owners, revenues, net of costs, were disbursed to (received

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from) Messrs. Goodson and Green, or their affiliates, in the amounts of \$(45,000) and \$30,000, respectively, and with respect to Mr. Nordberg, costs billed exceeded revenues disbursed in the amount of \$300. During 2014, in their capacities as working interest owners or overriding royalty interest owners, revenues, net of costs, were disbursed to Messrs. Goodson and Green, or their affiliates, in the amounts of \$80,000 and \$116,000, respectively, and with respect to Mr. Nordberg, costs billed equaled revenues disbursed. No such disbursements were made to Mr. Rucks during any reported period. With respect to Mr. Goodson, gross revenues attributable to interests, properties or participation rights held by him prior to joining the Company as an officer and director on September 1, 1998 represent all of the gross revenue received by him during these periods.

In its capacity as operator, the Company incurs drilling and operating costs that are billed to its partners based on their respective working interests. At December 31, 2016, the Company's joint interest billing receivable included approximately \$8,000 from the related parties discussed above or their affiliates, attributable to their share of costs. This represents less than 1% of the Company's total joint interest billing receivable at December 31, 2016.

Periodically, the Company charters private aircraft for business purposes. During 2014, the Company paid approximately \$18,000 to a third party operator in connection with the Company's use of flight hours owned by Charles T. Goodson through a fractional ownership arrangement with the third party operator. These amounts represent the cost of the hours purchased by Mr. Goodson. No such amounts were incurred during 2016 and 2015. The Company's use of flight hours purchased by Mr. Goodson was pre-approved by the Company's Audit Committee and there is no agreement or obligation by or on behalf of the Company to utilize this aircraft arrangement.

### **Note 11—Ceiling Test Write-down**

The Company uses the full cost method to account for its oil and gas properties. Accordingly, the costs to acquire, explore for and develop oil and gas properties are capitalized. Capitalized costs of oil and gas properties, net of accumulated DD&A and related deferred taxes, are limited to the estimated future net cash flows from estimated proved oil and gas reserves, including the effects of cash flow hedges in place, discounted at 10%, plus the lower of cost or fair value of unproved properties, as adjusted for related income tax effects (the full cost ceiling). If capitalized costs exceed the full cost ceiling, the excess is charged to ceiling test write-down of oil and gas properties in the quarter in which the excess occurs.

In accordance with SEC requirements, the estimated future net cash flows from estimated proved reserves are based on an average of the first day of the month spot price for a historical 12-month period, adjusted for quality, transportation fees and market differentials. At December 31, 2016 and 2015, the prices used in computing the estimated future net cash flows from the Company's estimated proved reserves, including the effect of hedges in place at that date, averaged \$2.51 and \$2.42, respectively, per Mcf of natural gas, \$40.85 and \$50.29, respectively, per barrel of oil and \$1.82 and \$2.21, respectively, per Mcfe of Ngl. As a result of lower commodity prices and their negative impact on the Company's estimated proved reserves and estimated future net cash flows, the Company recognized ceiling test write-downs of approximately \$40.3 million and \$266.6 million, respectively, during 2016 and 2015. The Company did not recognize a ceiling test write-down in the fourth quarter of 2016. The Company's cash flow hedges in place at December 31, 2015 decreased the ceiling test write-down by approximately \$1.1 million. The Company did not recognize a ceiling test write-down during 2014.



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### Note 12—Other Comprehensive Income (Loss)

The following table represents the changes in accumulated other comprehensive income (loss), net of tax, for the year ended December 31, 2015 (in thousands):

	Gains and Losses on Cash Flow Hedges
Balance as of December 31, 2014	\$ 5,420
Other comprehensive income before reclassifications:	
Change in fair value of derivatives	9,991
Income tax effect	(3,716)
Net of tax	6,275
Amounts reclassified from accumulated other comprehensive income:	
Oil and gas sales	(17,114)
Income tax effect	6,366
Net of tax	(10,748)
Net other comprehensive loss	(4,473)
Balance as of December 31, 2015	\$ 947

The following table represents the changes in accumulated other comprehensive income (loss), net of tax, for the year ended December 31, 2016 (in thousands):

	Gains and Losses on Cash Flow Hedges	Change in Valuation Allowance	Total
Balance as of December 31, 2015	\$ 947	\$ —	\$ 947
Other comprehensive income before reclassifications:			
Change in fair value of derivatives	(4,447)	—	(4,447)
Income tax effect	1,654	(1,654)	—
Net of tax	(2,793)	(1,654)	(4,447)
Amounts reclassified from accumulated other comprehensive income:			
Oil and gas sales	(1,811)	—	(1,811)
Income tax effect	674	(113)	561
Net of tax	(1,137)	(113)	(1,250)
Net other comprehensive loss	(3,930)	(1,767)	(5,697)
Balance as of December 31, 2016	\$ (2,983)	\$ (1,767)	\$ (4,750)

### Note 13—Income Taxes

The Company typically provides for income taxes at a statutory rate of 35% adjusted for permanent differences expected to be realized, primarily statutory depletion, non-deductible stock compensation expenses and state income taxes. As a result of ceiling test write-downs, the Company has incurred a three-year cumulative loss. Because of the impact the cumulative loss had on the determination of the recoverability of deferred tax assets through future earnings, the Company assessed the realizability of its deferred tax assets based on the future reversals of existing deferred tax liabilities. The Company had a valuation allowance of \$177.4 million as of December 31, 2016.

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An analysis of the Company's deferred tax assets and liabilities follows (amounts in thousands):

	December 31,	
	2016	2015
Net operating loss carryforwards	\$ 92,072	\$ 51,519
Percentage depletion carryforward	9,372	10,592
Alternative minimum tax credits	784	784
Contributions carryforward and other	282	266
Temporary differences:		
Oil and gas properties	27,992	62,786
Asset retirement obligation	13,620	15,831
Derivatives	1,767	(561)
Share-based compensation	1,870	2,291
Original issue discount on debt exchanges	29,646	—
Valuation allowance	(177,405)	(143,508)
Deferred tax asset (liability)	<u>\$ —</u>	<u>\$ —</u>

At December 31, 2016, the Company had approximately \$260.1 million of operating loss carryforwards, of which \$12.6 million relates to excess tax benefits with respect to share-based compensation that have not been recognized in the financial statements. If not utilized, approximately \$6.9 million of such carryforwards would expire in 2025 and the remainder would expire by the year 2036. The Company has available for tax reporting purposes \$26.8 million in statutory depletion deductions that may be carried forward indefinitely.

Income tax expense (benefit) for each of the years ended December 31, 2016, 2015 and 2014 was different than the amount computed using the Federal statutory rate (35%) for the following reasons (amounts in thousands):

	For the Year Ended December 31,		
	2016	2015	2014
Amount computed using the statutory rate	\$ (31,623)	\$ (102,257)	\$ 9,887
Increase (reduction) in taxes resulting from:			
State & local taxes	(2,000)	(6,477)	904
Percentage depletion carryforward	(163)	(404)	(1,564)
Non-deductible stock option expense (1)	77	90	213
Share-based compensation (2)	707	1,317	90
Other	1,415	113	(643)
Change in valuation allowance	32,130	110,244	(11,828)
Income tax expense (benefit)	<u>\$ 543</u>	<u>\$ 2,626</u>	<u>\$ (2,941)</u>

- (1) Relates to compensation expense recognized on the vesting of Incentive Stock Options.
- (2) Relates to the write-off of deferred tax assets associated with share-based compensation that will not be deductible for tax purposes.

### Note 14—Commitments and Contingencies

The Company is involved in litigation relating to claims arising out of its operations in the normal course of business, including worker's compensation claims, tort claims and contractual disputes. Some of the existing known claims against us are covered by insurance subject to the limits of such policies and the payment of deductible amounts by us. Although we cannot predict the outcome of these proceedings with certainty, management believes that the ultimate disposition of all uninsured or unindemnified matters resulting from existing litigation will not have a material adverse effect on the Company's business or financial position.

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### Lease Commitments

The Company has operating leases for office space and equipment, which expire on various dates through 2023. Future minimum lease commitments as of December 31, 2016 under these operating leases are as follows (in thousands):

2017	\$	1,208
2018		470
2019		447
2020		445
2021		434
Thereafter		811
	<u>\$</u>	<u>3,815</u>

Total rent expense under operating leases was approximately \$1.5 million, \$1.7 million and \$1.6 million in 2016, 2015 and 2014, respectively.

### Note 15—Supplementary Information on Oil and Gas Operations—Unaudited

The following tables disclose certain financial data relative to the Company's oil and gas producing activities, which are located onshore and offshore in the continental United States:

#### Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities (amounts in thousands)

	For the Year-Ended December 31,		
	2016	2015	2014
<b>Acquisition costs:</b>			
Proved	\$ 3,346	\$ 2,287	\$ 3,064
Unproved (1)	2,197	2,550	39,164
Divestiture of proved leasehold	(7,000)	—	—
<b>Exploration costs:</b>			
Proved	715	29,322	67,297
Unproved	603	7,677	13,515
Development costs	1,522	9,888	55,722
Capitalized general and administrative and interest costs	7,558	12,881	22,121
Total costs incurred	<u>\$ 8,941</u>	<u>\$ 64,605</u>	<u>\$ 200,883</u>

	For the Year-Ended December 31,		
	2016	2015	2014
<b>Accumulated depreciation, depletion and amortization (DD&amp;A)</b>			
Balance, beginning of year	\$ (1,157,455)	\$ (1,648,060)	\$ (1,553,044)
Provision for DD&A	(27,962)	(62,138)	(86,406)
Ceiling test writedown	(40,304)	(266,562)	—
Sale of proved properties and other (2) (3)	(17,565)	819,305	(8,610)
Balance, end of year	<u>\$ (1,243,286)</u>	<u>\$ (1,157,455)</u>	<u>\$ (1,648,060)</u>
DD&A per Mcfe	<u>\$ 1.19</u>	<u>\$ 1.82</u>	<u>\$ 1.99</u>

- (1) During 2014, the Company entered into a joint venture in Louisiana for an aggregate purchase price of \$24 million for an approximate 30,000 acre leasehold position.

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- (2) During 2015, the Company sold its Woodford Shale and Mississippian Lime assets for an aggregate cash purchase price of \$274.1 million (see Note 2).
- (3) During 2016, the Company sold its remaining Oklahoma producing assets for an aggregate purchase price of \$17.6 million. During 2015, the Company sold its Fort Trinidad assets for net proceeds of approximately \$0.5 million and its East Haynesville assets for net proceeds of approximately \$0.1 million. During 2014, the Company sold its Eagle Ford assets for net proceeds of approximately \$9.8 million.

At December 31, 2016 and 2015, unevaluated oil and gas properties totaled \$9.0 million and \$12.5 million, respectively, and were not subject to depletion. Unevaluated costs at December 31, 2016 included \$0.4 million of costs related to one development well in progress at year-end. These costs are expected to be transferred to evaluated oil and gas properties during 2017 upon the completion of drilling. At December 31, 2015, unevaluated costs included \$0.2 million related to 2 exploratory wells in progress. All of these costs were transferred to evaluated oil and gas properties during 2016. The Company capitalized \$0.9 million, \$4.7 million and \$10.0 million of interest during 2016, 2015 and 2014, respectively. Of the total unevaluated oil and gas property costs of \$9.0 million at December 31, 2016, \$3.4 million, or 38%, was incurred in 2016, \$1.1 million, or 12%, was incurred in 2015 and \$4.5 million, or 50%, was incurred in prior years. The Company expects that the majority of the unevaluated costs at December 31, 2016 will be evaluated within the next three years, including \$1.8 million that the Company expects to be evaluated during 2017.

### Oil and Gas Reserve Information

The Company's net proved oil and gas reserves at December 31, 2016 have been estimated by independent petroleum engineers in accordance with guidelines established by the SEC using a historical 12-month, first of month, average pricing assumption.

The estimates of proved oil and gas reserves constitute those quantities of oil, gas, and natural gas liquids, 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. However, there are numerous uncertainties inherent in estimating quantities of proved reserves and in providing the future rates of production and timing of development expenditures. The following reserve data represents estimates only and should not be construed as being exact. In addition, the present values should not be construed as the current market value of the Company's oil and gas properties or the cost that would be incurred to obtain equivalent reserves.

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The following table sets forth an analysis of the Company's estimated quantities of net proved and proved developed oil (including condensate), gas and natural gas liquid reserves, all located onshore and offshore in the continental United States:

	Oil in MBbls	NGL in MMcfe	Natural Gas in MMcf	Total Reserves in MMcfe
Proved reserves as of December 31, 2013	3,031	28,430	250,109	296,723
Revisions of previous estimates	(37)	2,894	9,976	12,650
Extensions, discoveries and other additions	475	49,990	82,364	135,205
Sale of reserves in place	(229)	(334)	(2,396)	(4,105)
Production	(803)	(7,482)	(31,028)	(43,325)
Proved reserves as of December 31, 2014	2,437	73,498	309,025	397,148
Revisions of previous estimates	(211)	(3,571)	(9,852)	(14,698)
Extensions, discoveries and other additions	163	16,078	45,645	62,702
Sale of reserves in place	(54)	(45,692)	(186,972)	(232,988)
Production	(529)	(5,487)	(25,502)	(34,160)
Proved reserves as of December 31, 2015	1,806	34,826	132,344	178,004
Revisions of previous estimates	247	(4,380)	(11,854)	(14,748)
Extensions, discoveries and other additions	—	—	1,485	1,485
Sale of reserves in place	(154)	—	(24,834)	(25,759)
Production	(502)	(3,871)	(16,617)	(23,501)
Proved reserves as of December 31, 2016	1,397	26,575	80,524	115,481
<u>Proved developed reserves</u>				
As of December 31, 2014	2,089	42,584	182,567	237,688
As of December 31, 2015	1,549	15,792	78,533	103,615
As of December 31, 2016	1,212	13,073	47,349	67,694
<u>Proved undeveloped reserves</u>				
As of December 31, 2014	348	30,914	126,458	159,460
As of December 31, 2015	257	19,034	53,811	74,389
As of December 31, 2016	185	13,502	33,175	47,787

### *Year Ended December 31, 2016*

During 2016, the Company's estimated proved reserves decreased by 35%. The decline in reserves was primarily due to the divestiture of the Company's remaining Oklahoma assets and significant reductions in capital spending during 2016. Extensions, discoveries and other additions of 1.5 Bcfe were primarily due to the successful completion of the Company's final Oklahoma wells. Revisions of previous estimates included the reclassification of certain PUD reserves to probable reserves as a result of the Company's assessment of the timing of development. Overall, the Company had a 100% drilling success rate during 2016 on five gross wells drilled.

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### Year Ended December 31, 2015

During 2015, the Company's estimated proved reserves decreased by 55% primarily due to the divestiture of the majority of the Company's Woodford Shale and Mississippian Lime assets. Extensions, discoveries and other additions of 63 Bcfe were primarily due to successful drilling programs in the Company's Oklahoma and East Texas fields. The Company added approximately 17 Bcfe of proved reserves in Oklahoma and 44 Bcfe in Texas. Overall, the Company had a 95% drilling success rate during 2015 on 56 gross wells drilled.

### Year Ended December 31, 2014

During 2014, the Company's estimated proved reserves increased by 34%. Extensions, discoveries and other additions of 135 Bcfe were primarily due to successful drilling programs in the Company's Oklahoma and East Texas fields and its Thunder Bayou discovery. The Company added approximately 72 Bcfe of proved reserves in Oklahoma, 46 Bcfe in Texas and 15 Bcfe in the Gulf Coast. Overall, the Company had a 91% drilling success rate during 2014 on 58 gross wells drilled.

The following tables (amounts in thousands) present the standardized measure of future net cash flows related to proved oil and gas reserves together with changes therein, as defined by ASC Topic 932. Future production and development costs are based on current costs with no escalations. Estimated future cash flows have been discounted to their present values based on a 10% annual discount rate.

### Standardized Measure

	December 31,		
	2016	2015	2014
Future cash flows	\$ 299,035	\$ 487,834	\$ 1,711,404
Future production costs	(117,283)	(171,678)	(372,690)
Future development costs	(83,720)	(116,591)	(244,784)
Future income taxes	—	—	(121,192)
Future net cash flows	98,032	199,565	972,738
10% annual discount	(30,763)	(71,880)	(424,176)
Standardized measure of discounted future net cash flows	<u>\$ 67,269</u>	<u>\$ 127,685</u>	<u>\$ 548,562</u>

### Changes in Standardized Measure

	Year Ended December 31,		
	2016	2015	2014
Standardized measure at beginning of year	\$ 127,685	\$ 548,562	\$ 451,180
Sales and transfers of oil and gas produced, net of production costs	(35,993)	(55,849)	(173,540)
Changes in price, net of future production costs	(30,427)	(267,710)	37,204
Extensions and discoveries, net of future production and development costs	864	70,928	237,290
Changes in estimated future development costs, net of development costs incurred during this period	26,356	31,007	11,094
Revisions of quantity estimates	(14,889)	(14,427)	25,591
Accretion of discount	12,769	60,071	47,130
Net change in income taxes	—	52,149	(32,034)
Sale of reserves in place	(16,701)	(194,454)	(7,240)
Changes in production rates (timing) and other	(2,395)	(102,592)	(48,113)
Net increase (decrease) in standardized measure	<u>(60,416)</u>	<u>(420,877)</u>	<u>97,382</u>
Standardized measure at end of year	<u>\$ 67,269</u>	<u>\$ 127,685</u>	<u>\$ 548,562</u>

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The historical twelve-month, first day of the month, average prices of oil, gas and natural gas liquids used in determining standardized measure were:

	2016	2015	2014
Oil, \$/Bbl	\$40.85	\$50.29	\$96.45
Ngls, \$/Mcf	2.40	2.24	4.11
Natural Gas, \$/Mcf	1.82	2.41	3.80

### Note 16 - Summarized Quarterly Financial Information - Unaudited

Summarized quarterly financial information is as follows (amounts in thousands except per share data):

	Quarter Ended			
	March 31	June 30	September 30	December 31
<b>2016:</b>				
Revenues	\$ 17,320	\$ 15,824	\$ 17,094	\$ 16,429
Loss from operations (1)	(37,557)	(22,383)	(22,039)	(8,374)
Loss available to common stockholders (1)	(39,137)	(24,143)	(23,306)	(9,659)
Earnings per share:				
Basic	\$ (2.09)	\$ (1.38)	\$ (1.31)	\$ (0.46)
Diluted	\$ (2.09)	\$ (1.38)	\$ (1.31)	\$ (0.46)
<b>2015:</b>				
Revenues	\$ 33,451	\$ 32,550	\$ 26,872	\$ 23,096
Loss from operations (2)	(121,887)	(57,796)	(50,617)	(61,864)
Loss available to common stockholders (2)	(122,240)	(61,083)	(51,910)	(64,696)
Earnings per share:				
Basic	\$ (7.55)	\$ (3.77)	\$ (3.19)	\$ (3.94)
Diluted	\$ (7.55)	\$ (3.77)	\$ (3.19)	\$ (3.94)

(1) Loss from operations and loss available to common stockholders reported during the three months ended March 31, June 30 and September 30, 2016 included pretax ceiling test write-downs of \$18.9 million, \$12.8 million and \$8.7 million, respectively.

(2) Loss from operations and loss available to common stockholders reported during the three months ended March 31, June 30, September 30 and December 31, 2015 included pretax ceiling test write-downs of \$108.9 million, \$65.5 million, \$40.2 million and \$51.9 million, respectively. Additionally, loss from operations and loss available to common stockholders reported during the three months ended June 30, 2015 included a pretax gain on sale of oil and gas properties of \$21.5 million.

# CORPORATE INFORMATION

## BOARD OF DIRECTORS

### **Charles T. Goodson**

Chairman of the Board,  
Chief Executive Officer, and President

### **William W. Rucks, IV \*# ^**

Private Investments

### **E. Wayne Nordberg \*# ^**

Hollow Brook Associates, LLC

### **W.J. Gordon III \*# ^**

President, CEO, and Founder of TGA Global Consulting Group

### **Charles F. Mitchell II, M.D. \*# ^**

Physician, Private Investments

### **J. Gerard Jolly \*# ^**

CPA, Retired Partner at KPMG LLP

\* Member of the Compensation Committee

# Member of the Audit Committee

^ Member of the Nominating and Corporate Governance Committee

## SENIOR MANAGEMENT

### **Charles T. Goodson**

Chairman of the Board,  
Chief Executive Officer, and President

### **J. Bond Clement**

Executive Vice President  
Chief Financial Officer, and Treasurer

### **Art M. Mixon**

Executive Vice President  
Operations and Production

### **Edward E. Abels, Jr.**

Executive Vice President, General Counsel,  
and Corporate Secretary

### **Stephen H. Green**

Senior Vice President  
Exploration

### **Edgar A. Anderson**

Vice President - ArkLaTex

## CORPORATE ADDRESS

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400 East Kaliste Saloom Road, Suite 6000  
Lafayette, Louisiana 70508  
Telephone: (337) 232-7028  
Fax: (337) 232-0044  
Web: [www.petroquest.com](http://www.petroquest.com)

## EXPLORATION OFFICE

1800 Hughes Landing Blvd., Suite 200  
The Woodlands, Texas 77380  
Telephone: (281) 465-3900  
Fax: (281) 465-3999

## TRANSFER AGENT AND REGISTRAR

American Stock Transfer & Trust Company  
59 Maiden Lane  
New York, New York 10038  
Telephone: (718) 921-8145

## INDEPENDENT AUDITORS

Ernst & Young LLP  
New Orleans, Louisiana 70170

## LEGAL COUNSEL

Porter & Hedges, LLP  
Houston, Texas 77002

Onebane Law Firm  
Lafayette, Louisiana 70508

## ANNUAL MEETING

The Company's Annual Meeting of Stockholders will be held at 9:00 A.M. CDT on May 16, 2017, at the City Club at River Ranch at 221 Elysian Fields Drive, Lafayette, Louisiana, 70508.

## FORM 10-K

Copies of the Company's Annual Report on Form 10-K may be obtained, without charge, by writing to our Corporate Secretary at our Corporate Address or on the Company's website at [www.petroquest.com](http://www.petroquest.com).

## COMMON STOCK LISTING

Listed on NYSE as PQ



 PetroQuest Energy, Inc.

[WWW.PETROQUEST.COM](http://WWW.PETROQUEST.COM)

**NYSE:PQ**