PetroQuest Energy, Inc.

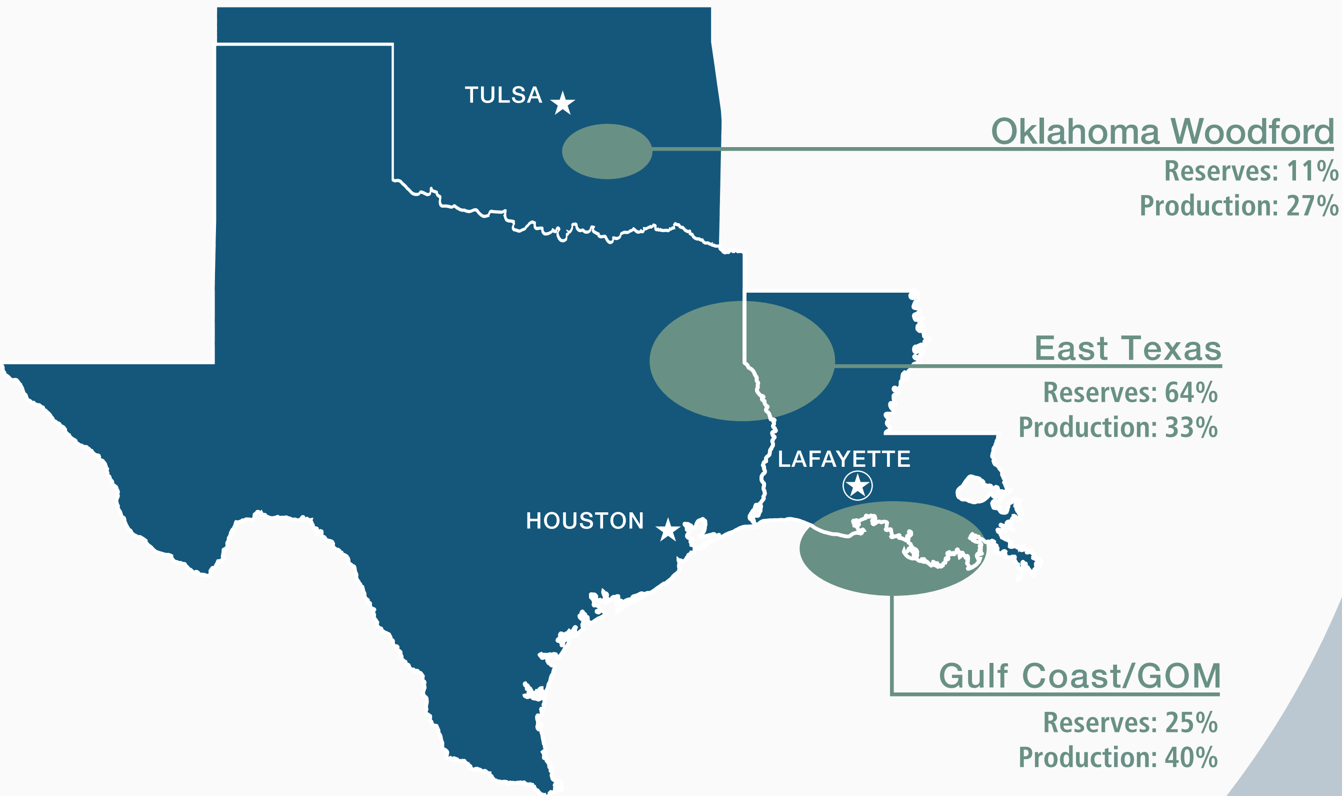
2015

Annual Report

Corporate Profile

Founded in 1985, PetroQuest Energy is a U.S.-focused exploration and development company of crude oil and natural gas in Louisiana, Oklahoma 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



Letter To Shareholders

Charles T. Goodson
Chairman, President & CEO

Dear Fellow Shareholders:

Everyone has made their best guess about how long this downturn will last. Instead of guessing, we took proactive steps to prepare for a lower for longer commodity price scenario. We sold non-core assets in the Mid-Continent, paid off all of our bank debt and closed on a private exchange offer that lowered our debt profile, extended maturities and substantially reduced annual fixed charges. In response to the lower commodity price environment, our 2016 capital expenditure guidance is approximately 70% less than 2015 showing our commitment to cost control and liquidity preservation.

If there is a bright spot in the current commodity environment, we believe it's the future for natural gas. Domestic supply and demand fundamentals are rapidly changing for the better. On the supply side of the equation, the natural gas rig count is now below 100 rigs working, off of the 2015 high seen in January at 329 gas rigs. As a result, we are seeing natural gas production begin to roll over. Natural gas demand, notwithstanding the mild winter, is increasing as natural gas is replacing coal as a cleaner and more cost effective alternative for domestic power generation, and U.S. liquefied natural gas (LNG) is now being exported overseas. The first lower 48 U.S. LNG export ship left Cameron Parish, Louisiana on February 24 to deliver its shipment to Brazil. This historic event marks a new paradigm for the country in energy trade and allows U.S. producers to compete for global demand.

Our 30 year history in the oil and gas business taught us how to navigate turbulent markets. Success in a low price environment requires a quality asset base, liquidity and a relentless commitment from a team to recognize opportunities and preserve value. When prices recover, not only will we bridge to the other side of this downturn, but return to a growth path consistent with our execution over our long corporate history.

Significant Transactions

In June of 2015, we sold the majority of our interests in the Woodford Shale and Mississippian Lime for gross proceeds of $280 million. By moving quickly and efficiently, we were able to realize substantial value for these assets that provided an infusion of cash we in turn used to pay down debt. By focusing on two primary operating regions, instead of three, we can concentrate our capital and efforts on our highest return projects – our multi-year development of the Carthage Field in East Texas, where we've assembled a premier asset in the core of the Cotton Valley trend, and our low decline Gulf Coast projects at Thunder Bayou and La Cantera.

More recently in early 2016, we closed on a private exchange offer of $214.4 million of our outstanding 10% Senior Notes due 2017 for $53.6 million of cash, $144.6 million in aggregate principal of newly issued 10% Second Lien Senior Secured Notes due 2021 and 4.2 million shares of our common stock. The transaction extends the maturities of a significant portion of our debt out to 2021, eliminates $70 million in debt, and reduces our annual interest payments by $7 million a year. In total, since the end of 2014, we have extinguished approximately $145 million in debt. We estimate that the resulting reduction in interest expense will provide an approximate $0.33/Mcfe improvement on 2016 cash margins.

Quality Assets

Despite our Mid-Continent asset divestiture, we never lost focus on development of core assets in East Texas and the Gulf Coast. In June of 2015, we initiated production from our single most impactful project in the Company's 30 year history - Thunder Bayou. The well's initial production rate of 41 MMcfe/d exceeded our original expectations and today, after being online for more than 9 months, the well continues to flow at 30 MMcfe/d, once again exceeding our expectations. We are currently producing from the lower Cris R2 zone and are forecasting a recompletion into the primary upper Cris R2 zone mid-year 2016. This recompletion is expected to significantly increase the well's production rate, which will be the main contributor to our relatively stable 2016 corporate production profile. Our Thunder Bayou and La Cantera discoveries are two of the largest discoveries in Louisiana over the last 10 years and are a testament to the talent of our Gulf Coast team. These projects, with approximately 330 Bcfe of projected recoverable reserves, should provide a stable long term cash flow profile with minimal future maintenance capital. This is the funding engine for future growth.

In the Cotton Valley, we have drilled a total of 20 horizontal wells with each incremental well leading to improved performance and decreasing well costs. Our most recent PQ #20 well was drilled and completed for $3.9 million, a 43% decline in cost when compared to our wells that were drilled in 2013. In addition, our PQ #20 well achieved a 24 hour maximum production rate of 14.8 MMcfe/d, a 134% increase compared to early vintage horizontal wells in 2011. Our Cotton Valley returns are as competitive as any of the premier oil and gas trends in North America. Just as we did in our Woodford assets, where we drove our spud through completion time, pre-frac from 46 days to under 10 days, we are moving quickly along the Cotton Valley learning curve. With state-of-the-art rigs and engineering, our goal is to reduce cost so these properties achieve full cycle returns that are profitable below $2.00 per MMBtu. With low initial decline production profiles and proximity to the Gulf Coast markets, we believe this is a very realistic goal.

During 2015, the Company grew proved reserves by approximately 5% as compared to proved reserves at December 31, 2014, proforma for the Oklahoma divestment in June 2015. We ended 2015 with approximately 178 Bcfe of estimated proved oil and gas reserves which do not include the unproved, behind pipe reserves associated with the Company's four producing wells at La Cantera and Thunder Bayou, estimated to total approximately $60 million in additional PV-10 value at December 31, 2015.

This reserve growth, despite the continued decline in oil and gas prices speaks volumes to the quality of our core assets in the Gulf Coast and East Texas. Now that we have simplified our development strategy into our two highest return and scalable assets, our Gulf Coast free cash flow can now be consistently directed to the development of the more than 600 identified Cotton Valley locations, which we expect will provide PetroQuest a long-term growth platform.

Built For The Future

During any downturn, successful companies must adapt to endure. These decisions are made by people. I truly believe an organization is only as good as its people and I'm encouraged by the industry talent we've been able to attract and retain. Our goal for 2016 is to survive. To that end, we are evaluating additional liquidity building opportunities and are fiercely implementing cost cutting initiatives. If we are in a lower for longer scenario, like I said before, we've positioned PetroQuest and its shareholders to weather the storm and realize significant growth when prices begin to recover.

Thank you for your continued support during these volatile times.

Sincerely,

Charles T. Goodson

Charles T. Goodson
Chairman, President and Chief Executive Officer
March 18, 2016

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K
(Mark One)

☒ **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended December 31, 2015
or

Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from to
Commission File Number: 001-32681

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, 2015, based on the $1.98 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 $84,213,000 (for purposes of this disclosure, the registrant assumed its directors, executive officers and beneficial owners of 5% or more of the registrant's Common Stock were affiliates).

As of February 26, 2016, the registrant had outstanding 70,534,569 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 18, 2016, 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;
- the effects of a financial downturn or negative credit market conditions on our liquidity, business and financial condition;
- 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 our bank credit facility and restrictive debt covenants;
- our ability to post additional collateral to satisfy our offshore decommissioning obligations:
- losses or limits on potential gains resulting from hedging production;
- our ability to find, develop, produce and acquire additional oil and natural gas reserves that are economically recoverable;
- approximately 40% 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;
- regulatory initiatives relating to oil and natural gas development, hydraulic fracturing, and derivatives;
- our ability to identify, execute or efficiently integrate future acquisitions;
- the loss of key management or technical personnel;
- ceiling test write-downs resulting, and that could result in the future, from lower oil and natural gas prices;
- losses and liabilities from uninsured or underinsured drilling and operating activities;
- 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;
- 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;

- governmental regulation relating to hydraulic fracturing and 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;

- 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 56.

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, the Gulf Coast Basin and Oklahoma. 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. 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.

We have successfully diversified into onshore, longer life basins through a combination of selective acquisitions and drilling activity, partially offset by our recent asset divestiture in Oklahoma as discussed below. As a result of our transition to lower-risk, longer life basins, we have realized a 95% drilling success rate on 913 gross wells drilled over the last 10 years. Comparing 2015 metrics with those in 2003, the year we implemented our diversification strategy, we have grown production by 254% and estimated proved reserves by 114%.

On June 4, 2015, we completed the sale of a majority of our interests in the Woodford and Mississippian Lime (the "Oklahoma Divestiture") for $280 million, subject to customary post-closing purchase price adjustments, effective January 1, 2015. At closing, we 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, we entered into a Contract Operating Services Agreement whereby we will retain a minimal working interest in the properties sold in the Oklahoma Divestiture and will provide certain services as a contract operator for a period of one year from the closing date of the sale, subject to renewal for two additional one-year terms.

Balance Sheet Restructuring

In response to the decline in commodity prices that began in late 2014, and has continued throughout 2015 and into 2016, we have initiated the following steps designed to enhance liquidity and reduce indebtedness:

- Consummated the Oklahoma Divestiture in June 2015 for approximately $280 million;
- Repaid all borrowings outstanding under our bank credit facility with a portion of the net proceeds from the Oklahoma Divestiture;
- Reduced capital expenditures during 2015 by 67%, as compared to 2014;
- Approved a 2016 capital expenditure budget down 65% from 2015 spending;
- Completed an Exchange Offering (as described below) in February 2016 that reduced indebtedness by $69.7 million and extended the maturity on $144.7 million of indebtedness from September 2017 to February 2021; and
- Announced plans to suspend the dividend on our Series B Preferred Stock beginning with the April 2016 payment, which will save $5.1 million annually.

As a result of the actions outlined above, we have reduced our total indebtedness from $420.2 million at December 31, 2014 to $280.3 million as of the date of this report. Most recently, we completed a private exchange offering whereby participating bondholders exchanged approximately $214.4 million of 10% Senior Notes due 2017 for approximately $53.6 million in cash, approximately $144.7 million of our newly issued 10% Senior Secured Second Lien Notes due 2021 (the "10% senior secured notes") and approximately 4.3 million shares of our common stock (the "Exchange Offering"). As a result of the Exchange Offering, we reduced our annual fixed charges by $7 million and eliminated or extended the maturity date on 61% of our $350 million of indebtedness as of December 31, 2015. After completion of the Exchange Offering, we have $280.3 million of total indebtedness, with $135.6 million maturing in September 2017 and $144.7 million maturing in February 2021.

Business Strategy

Preserve Our Liquidity and Strengthen Our Balance Sheet. In response to the impact that the decline in commodity prices has had on our cash flow, our 2016 capital expenditures will be significantly reduced as compared to 2015. Our 2016 capital expenditures, which include capitalized interest and overhead but exclude acquisitions, are expected to range between $20 million and $25 million, a 65% reduction at the midpoint of that range from our spending in 2015, 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 13% 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. In addition, we plan to suspend the quarterly dividend on our outstanding Series B Preferred Stock beginning with the dividend payment due in April 2016 (which will save $5.1 million annually), reduce our cash costs by 25% from 2015 levels and consider additional options to refinance our remaining $135.6 million of 10% Senior Notes due 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 strike a balance between lower risk development activities and higher risk and higher impact exploration activities. While our reduced 2016 capital expenditure budget, combined with lower commodity prices, is expected to impact our near-term growth outlook, 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, 2015, approximately 75% of our estimated proved reserves were located in longer life and lower risk basins in Oklahoma and Texas and 25% were located in the shorter life, but higher flow rate reservoirs in the Gulf Coast Basin. In terms of production diversification, during 2015, 60% of our production was derived from longer life basins. Our 2015 production was comprised of 75% natural gas, 9% oil and 16% natural gas liquids.

Target Underexploited Properties with Substantial Opportunity for Upside. We plan to maintain a rigorous prospect selection process that enables us to leverage our operating and technical experience in our core operating areas. In evaluating these prospects, we seek properties that provide sufficient acreage for future exploration and development, as well as properties that may benefit from the latest exploration, drilling, completion and operating techniques to more economically find, produce and develop oil and gas reserves.

Concentrate in Core Operating Areas and Build Scale. We plan to continue focusing on our operations in 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.

2015 Financial and Operational Summary

During 2015, we invested $64.6 million in exploratory, development and acquisition activities. We drilled 29 gross exploratory wells and 27 gross development wells realizing an overall success rate of 95%. These activities were financed through our cash flow from operations and proceeds from the Oklahoma Divestiture. During 2015, our production decreased 21% to 34.2 Bcfe as a result of the Oklahoma Divestiture and normal production declines at our Gulf Coast fields. Our estimated proved reserves at December 31, 2015 decreased 55% from 2014 as discussed in greater detail below.

Oil and Gas Reserves

Our estimated proved reserves at December 31, 2015 decreased 55% from 2014 totaling 1.8 MMBbls of oil, 34.8 Bcfe of natural gas liquids (Ngls) and 132 Bcf of natural gas, with a pre-tax present value, discounted at 10%, of the estimated future net revenues based on average prices during 2015 ("PV-10") of $127.7 million. The decrease in our estimated proved reserves during 2015 was primarily the result of the Oklahoma Divestiture, which represented 227.2 Bcfe of our estimated proved reserves as of December 31, 2014 with $248.9 million of PV-10. At December 31, 2015, our standardized measure of discounted cash flows, which includes the estimated impact of future income taxes, totaled $127.7 million. See the reconciliation of PV-10 to the standardized measure of discounted cash flows below. Our PV-10 and standardized measure of discounted cash flows utilized prices (adjusted for field differentials) for the years ended December 31, 2015 and 2014 as follows:

	12/31/2015	12/31/2014
Oil per Bbl	$50.29	$96.45
Natural gas per Mcf	$2.41	$3.80
Ngl per Mcfe	$2.24	$4.11

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, 2015. Our internal reservoir engineering staff is managed by an individual with 34 years of industry experience as a reservoir and production engineer, including thirteen years as a reservoir engineering manager with PetroQuest. This individual is responsible for overseeing the estimates prepared by Ryder Scott.

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 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 96% drilling success rate on 28 gross wells drilled in East Texas where 95% of our PUD reserves are currently booked. Furthermore, because all of our longer life, onshore PUD reserves (100% of total PUD reserve volumes at December 31, 2015) 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, 2015:

	Oil (MBbls)	NGL (Mmcfe)	Natural Gas (Mmcf)	Total Mmcfe*
Proved Developed	1,549	15,792	78,533	103,615
Proved Undeveloped	257	19,034	53,811	74,389
Total Proved	1,806	34,826	132,344	178,004

* 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, 2015, our PUD reserves totaled 74.4 Bcfe, a 53% decrease from our PUD reserves at December 31, 2014. This decrease was primarily due to the sale of PUDs associated with the Oklahoma Divestiture. During 2015, we spent $8.7 million converting 23 Bcfe of PUD reserves at December 31, 2014 to proved developed reserves at December 31, 2015. In addition, at December 31, 2015, we had five wells in progress that are estimated to convert 9 Bcfe of PUD reserves in 2016.

The following table presents an analysis of the change in our PUD reserves from December 31, 2014 to December 31, 2015:

	MMcfe
PUD Reserve balance at December 31, 2014	159,460
PUD reserves converted to proved developed	(22,983)
PUD reserves added from extensions, discoveries and revisions	29,190
PUD reserves sold	(91,278)
PUD Reserve balance at December 31, 2015	74,389

Approximately 5% and 95% of our PUD reserves at December 31, 2015 were associated with the future development of our Oklahoma and East Texas properties, respectively. We expect all of our PUD reserves at December 31, 2015 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 2015 we spent $20.5 million converting 25.4 Bcfe of reserves that were classified as probable reserves at December 31, 2014 to proved developed producing at December 31, 2015 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, 2015, 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 $3.1 million in 2016, $21.7 million in 2017, $5.2 million in 2018, $20.4 million in 2019 and $18.5 million in 2020.

The estimated cash flows from our proved reserves at December 31, 2015 were as follows:

	Proved Developed (M$)	Proved Undeveloped (M$)	Total Proved (M$)
Estimated pre-tax future net cash flows (1)	$ 141,208	$ 58,357	$ 199,565
Discounted pre-tax future net cash flows (PV-10) (1)	$ 111,874	$ 15,811	$ 127,685
Total standardized measure of discounted future net cash flows			$ 127,685

(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, 2015:

	Total Proved (M$)
Estimated pre-tax future net cash flows	$ 199,565
10% annual discount	(71,880)
Discounted pre-tax future net cash flows	127,685
Future income taxes discounted at 10%	—
Standardized Measure of discounted future net cash flows	$ 127,685

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, 2015 and 2014.

	2015		2014	
	Reserves	Production	Reserves	Production
East Texas	114.1	11.1	89.4	9.7
Gulf Coast Basin	43.9	13.8	55.1	16.3
Oklahoma Woodford (1)	20.0	9.2	252.4	16.9
Other	—	0.1	0.2	0.4
	178.0	34.2	397.1	43.3

(1) On June 4, 2015, we completed the Oklahoma Divestiture (representing 227.2 Bcfe of proved reserves at December 31, 2014) which contributed 7.0 Bcfe and 16.4 Bcfe of production in 2015 and 2014, respectively.

Oklahoma - Woodford

During 2015, we drilled and participated in 49 gross wells, achieving a 100% success rate. In total, we invested $13.2 million during 2015 acquiring prospective acreage and drilling and completing wells. Average daily production from our Oklahoma properties during 2015 totaled 25 MMcfe per day, a 45% decrease from 2014 average daily production primarily as a result of the Oklahoma Divestiture. We added approximately 17 Bcfe of estimated proved reserves from our drilling program during the year, but sold 239 Bcfe resulting in a 92% decrease in our estimated proved reserves. Other than capital required to convert PUDs in progress at the end of 2015, we have not allocated capital from our 2016 budget to operations in the Woodford Shale due to low commodity prices.

East Texas

During 2015, we invested $22.1 million in our East Texas properties where we drilled four gross wells, achieving a 100% success rate. Net production from our East Texas assets averaged 30.4 MMcfe per day during 2015, a 15% increase from 2014 average daily production and our estimated proved reserves increased 28% from 2014, as a result of successful drilling in our Carthage field. We have allocated approximately 33% of our 2016 capital budget to converting one PUD location and performing various re-completions and plugging and abandonment operations at our Carthage field.

Gulf Coast Basin

During 2015, we invested $34.1 million in this area including $6.1 million related to our Fleetwood joint venture and $17.0 million for the Thunder Bayou discovery which started producing in the second quarter of 2015. We also drilled three unsuccessful wells in this area in 2015. Production from this area decreased 15% from 2014 totaling 37.8 MMcfe per day in 2015 due to normal production declines in the Gulf Coast area and a pipeline shut-in during the fourth quarter of 2015. Our estimated proved reserves in this area decreased 20% from 2014 primarily as a result of the 13.8 Bcfe of current year production, offset by reserves from our Thunder Bayou discovery. We have allocated approximately 67% of our 2016 capital budget to performing various re-completions and plugging and abandonment projects in the Gulf Coast Basin.

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.

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 2015, one customer accounted for 21%, one accounted for 18%, one accounted 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. During 2013, one customer accounted for 35% and two accounted for 14% each 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.

Production, Pricing and Production Cost Data

The following table sets forth our production, pricing and production cost data during the periods indicated. Two of our core areas, Gulf Coast Basin and East Texas, represented approximately 15% or more of our total estimated proved reserves at December 31, 2015.

	Year Ended December 31, 2015	2014	2013
Production:			
Oil (Bbls):			
Gulf Coast Basin	473,846	687,855	512,041
East Texas	50,739	62,013	82,500
Oklahoma - Woodford	1,274	423	971
Other	2,670	52,218	85,468
Total Oil (Bbls)	528,529	802,509	680,980
Gas (Mcf):			
Gulf Coast Basin	9,421,031	10,825,424	9,876,771
East Texas	7,838,144	6,636,174	4,123,416
Oklahoma - Woodford	8,231,131	13,468,244	15,055,601
Other	11,545	97,829	170,055
Total Gas (Mcf)	25,501,851	31,027,671	29,225,843
NGL (Mcfe):			
Gulf Coast Basin	1,548,228	1,325,288	1,312,995
East Texas	2,946,185	2,672,885	1,333,725
Oklahoma - Woodford	985,838	3,398,750	1,971,376
Other	6,988	85,387	136,127
Total NGL (Mcfe)	5,487,239	7,482,310	4,754,223
Total Production (Mcfe):			
Gulf Coast Basin	13,812,335	16,277,842	14,262,012
East Texas	11,088,763	9,681,137	5,952,141
Oklahoma - Woodford	9,224,613	16,869,532	17,032,803
Other	34,553	496,524	818,990
Total Production (Mcfe)	34,160,264	43,325,035	38,065,946
Average sales prices (1):			
Oil (per Bbl):			
Gulf Coast Basin	$ 48.94	$ 96.71	$ 105.74
East Texas	48.28	92.21	98.61
Oklahoma - Woodford	52.26	97.04	90.52
Other	50.23	95.74	97.59
Total Oil (per Bbl)	48.89	96.30	103.83
Gas (per Mcf)			
Gulf Coast Basin	2.55	4.38	3.70
East Texas	2.63	4.08	3.73
Oklahoma - Woodford	1.75	3.27	2.25
Other	3.17	4.04	3.54
Total Gas (per Mcf)	2.32	3.83	2.95
NGL (per Mcfe)			
Gulf Coast Basin	3.03	6.00	7.12
East Texas	1.94	4.17	4.70
Oklahoma - Woodford	3.49	3.63	4.31
Other	3.94	5.55	5.21
Total NGL (per Mcfe)	2.53	4.27	5.22
Total Per Mcfe:			
Gulf Coast Basin	3.76	7.49	7.02
East Texas	2.60	4.54	5.00
Oklahoma - Woodford	1.94	3.34	2.49
Other	5.74	11.82	11.79
Total Per Mcfe	2.89	5.26	4.78

	Year Ended December 31,		
	2015	2014	2013
Average Production Cost per Mcfe (2):			
Gulf Coast Basin	$ 1.86	$ 1.59	$ 1.60
East Texas	0.90	1.21	1.47
Oklahoma - Woodford	0.45	0.52	0.47
Other	8.69	4.56	5.03
Total Average Production Cost per Mcfe	1.17	1.12	1.15

(1) Does not include the effect of hedges.
(2) Production costs do not include production taxes.

Oil and Gas Producing Wells

The following table details the productive wells in which we owned an interest as of December 31, 2015:

	Gross	Net
Productive Wells:		
Oil:		
Gulf Coast Basin	7	2.86
East Texas	—	—
Oklahoma - Woodford	1	0.03
Other	—	—
	8	2.89
Gas:		
Gulf Coast Basin	15	7.94
East Texas	98	65.09
Oklahoma - Woodford	392	101.32
Other	—	—
	505	174.35
Total	513	177.24

Of the 513 gross productive wells at December 31, 2015, one had dual completions.

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.

	2015		2014		2013	
	Gross	Net	Gross	Net	Gross	Net
Exploration:						
Productive:						
Gulf Coast Basin	—	—	2	1.19	1	0.94
East Texas	4	3.31	4	3.10	1	0.99
Oklahoma - Woodford	22	5.05	15	6.58	22	5.66
Other	—	—	4	0.56	7	2.11
	26	8.36	25	11.43	31	9.70
Non-productive:						
Gulf Coast Basin	3	1.22	2	1.12	3	0.62
East Texas	—	—	—	—	—	—
Oklahoma - Woodford	—	—	—	—	—	—
Other	—	—	2	2.00	2	0.62
	3	1.22	4	3.12	5	1.24
Total	29	9.58	29	14.55	36	10.94
Development:						
Productive:						
Gulf Coast Basin	—	—	—	—	1	0.24
East Texas	—	—	2	1.55	—	—
Oklahoma - Woodford	27	4.30	24	5.86	3	1.36
Other	—	—	2	0.19	—	—
	27	4.30	28	7.60	4	1.60
Non-productive:						
Gulf Coast Basin	—	—	—	—	—	—
East Texas	—	—	—	—	—	—
Oklahoma - Woodford	—	—	1	0.50	—	—
Other	—	—	—	—	—	—
	—	—	1	0.50	—	—
Total	27	4.30	29	8.10	4	1.60

At December 31, 2015, we had 7 gross (1.80 net) wells in progress.

Leasehold Acreage

The following table shows our approximate developed and undeveloped (gross and net) leasehold acreage as of December 31, 2015:

	Leasehold Acreage			
	Developed		Undeveloped	
	Gross	Net	Gross	Net
Kansas	—	—	2,563	1,282
Louisiana	4,833	2,002	8,241	3,161
Mississippi	721	721	—	—
Oklahoma	59,698	21,900	277	87
Texas	40,864	21,534	7,285	4,222
Federal Waters	51,639	32,450	7,124	7,124
Total	157,755	78,607	25,490	15,876

Leases covering 17% of our net undeveloped acreage are scheduled to expire in 2016, 9% in 2017, 9% in 2018 and 65% thereafter. At December 31, 2015, 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 2016, 57% relates to undeveloped acreage in the Fleetwood area in South Louisiana where we are currently evaluating future plans.

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 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 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 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, NEPA 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 and the BSEE generally require 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. The cost of compliance with these supplemental bonding requirements has not been material. 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 GOM 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 have made enforcement of decommissioning liabilities one of its top priorities. Recent DOI 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 recently requested that we post collateral to support certain of the bonds that are issued on our behalf. We are currently evaluating various options for posting the requested collateral, however, given the effect of current commodity prices on our creditworthiness and the unwillingness of the surety companies to post bonds without the requisite collateral, we cannot assure you that we will be able to satisfy current or 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 our agreements with the surety companies, which in turn could cause a cross-default under our bank credit facility and potentially the indenture governing our 10% senior secured notes.

In addition, we may be required to provide cash collateral or letters of credit to support the issuance of such bonds or other surety. Such letters of credit would likely be issued under our bank credit facility and would reduce the amount of borrowings available under such facility in the amount of any such letter of credit obligations. We can provide no assurance that we can continue to obtain bonds or other surety in all cases or that we will have sufficient availability under our bank credit facility to support such supplemental bonding requirements. If we are unable to obtain the additional required bonds or assurances as requested, the BOEM may require any of our operations on federal leases to be suspended, canceled or 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 or 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.

We generate wastes, including hazardous wastes, which are subject to regulation under the federal Resource Conservation and Recovery Act ("RCRA") and state statutes. The USEPA has limited the disposal options for certain hazardous wastes. Furthermore, it is possible that certain wastes generated by our oil and gas operations which are currently exempt from regulation 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.

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. For example, the American Burying Beetle, listed in 1989 as endangered, is present in regions overlying the Woodford Shale in Oklahoma. 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 $350 million and for offshore facilities of all removal costs plus $33.65 million, and lesser limits for some vessels depending upon their size. Effective December 2015, the Coast Guard has increased the liability limit for onshore facilities to $633.8 million based on an inflation adjustment. 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 has commissioned a study to identify potential risks associated with hydraulic fracturing. In June 2015, the USEPA released for public comment and peer review, a draft assessment of the potential impacts of hydraulic fracturing on drinking water resources. Additionally, the draft has generated substantial public comment and the USEPA’s Science Advisory Board has scheduled public meetings and teleconferences through at least March 2016 to receive comment on the study. The study’s findings are intended to improve scientific understanding to guide USEPA’s regulatory oversight, guidance and, where appropriate, rulemaking related to hydraulic fracturing. 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 Oklahoma. Depending on the results of the USEPA study and other developments related to the impact of hydraulic fracturing, 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 by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could impose civil and 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 (so-called green completions). Other new requirements mandate tighter standards for emissions associated with gas production, storage and transport. In August 2015, USEPA proposed rules to address methane emissions at new oil and gas wells and in January 2016, BLM proposed new rules to limit flaring on public and tribal lands. While these new requirements are 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 45,800 square feet of leased space, with exploration offices in The Woodlands, Texas and Tulsa, Oklahoma, in approximately 13,100 square feet and 11,800 square feet, respectively, 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.

Employees

We had 119 full-time employees as of February 8, 2016. 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, 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 oil prices have been significantly depressed since the end of 2014. The extended decline in the prices of oil and natural gas has adversely affected, and will continue to adversely affect our financial condition, liquidity 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 has decreased significantly as of December 31, 2015 as compared to December 31, 2014. For example, the SEC pricing at December 31, 2015 for crude oil (WTI Cushing) and natural gas (Henry Hub) was $50.28 per Bbl and $2.58 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, as to 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. Likewise we cannot predict how long the current downturn in crude oil and natural gas prices will continue. The extended decline in oil and natural gas prices has adversely affected, and may continue to adversely affect, our financial condition, liquidity 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 have required and may require us to record additional ceiling test write-downs and may cause our estimated proved reserves at December 31, 2016 to decline compared to our estimated proved reserves at December 31, 2015. 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 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, which in turn may limit our ability to 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, 2015 was $202.0 million. After giving effect to the the Exchange Offering, the aggregate principal amount of our outstanding indebtedness, net of cash on hand was $185.9 million. We currently have $42 million of availability under our bank credit facility, subject to compliance with the financial covenants thereunder, which, based on the Company's expectations for the first quarter of 2016, will effectively limit the availability to 25% of the aggregate commitment of the lenders, or $10.5 million. In addition, we may also incur additional indebtedness in the future. Specifically, 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 10% senior secured notes and our 10% Senior Notes due 2017 (the "10% senior notes"), 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, approximately $28 million per year for interest on our 10% senior secured notes and 10% senior notes alone, and to pay quarterly dividends (which we plan to suspend 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;
- the amount of our interest expense may increase because certain of our borrowings in the future may be at variable rates of interest, which, if interest rates increase, could result in higher interest expense;
- 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 10% senior secured notes and 10% senior notes, 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 10% senior secured notes and 10% senior notes, 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.

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 10% senior secured notes and 10% senior notes, 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 our bank credit facility in an amount sufficient to enable us to pay principal and interest on our indebtedness, including our 10% senior secured notes and 10% senior 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 10% senior secured notes and 10% senior notes, 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.

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 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 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 lenders from fully funding our bank credit facility or cause them to make the terms of our bank credit facility 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.

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.

The borrowing base under our bank credit facility may be reduced below the amount of borrowings outstanding under such facility.

Under the terms of our bank credit facility, our borrowing base is subject to redeterminations at least semi-annually (with additional interim redeterminations presently scheduled to occur) based in part on prevailing oil and gas prices. A negative adjustment could occur if the estimates of future prices used by the banks in calculating the borrowing base are significantly lower than those used in the last redetermination. The next redetermination of our borrowing base is scheduled to occur by March 31, 2016. In addition, the portion of our borrowing base made available to us is subject to the terms and covenants of the bank credit facility including, without limitation, compliance with the ratios and other financial covenants of such facility. Though we do not currently have any amounts outstanding, if the amount that may in the future be outstanding under our bank credit facility exceeds a redetermined borrowing base, we could be forced to repay a portion of our borrowings thereunder. We may not have sufficient funds to make any required repayment. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell a portion of our assets.

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.

Our bank credit facility and the indenture governing our 10% senior secured 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 to 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, our bank credit facility and the indenture governing our 10% senior secured notes require 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. For example, as a result of the impact of the decline in commodity prices, we anticipate that we may exceed the maximum ratio of total debt to EBITDAX financial covenant included in the bank credit facility as early as the end of the first quarter of 2016, which would require us to seek a waiver or amendment from the lenders. We cannot provide any assurance that we will be able to reach an agreement with the lenders on an amendment or waiver on a timely basis or on satisfactory terms to alleviate any non-compliance with the financial covenants under the bank credit facility.

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 our bank credit facility and the indenture governing our 10% senior secured 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 our bank credit facility and our 10% senior secured notes. A default, if not cured or waived, could result in all indebtedness outstanding under our bank credit facility and our 10% senior secured 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.

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, 2015 and as of the date of this report are in the form of swaps placed with the commodity trading branches of JPMorgan Chase Bank and The Bank of Nova Scotia, both of which participate in our bank credit facility. We cannot assure you that these 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, 2015, our total oil and gas sales included additions related to the settlement of gas hedges of $15,940,000, oil hedges of $644,000 and Ngl hedges of $530,000, which in total represented 15% 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, at March 1, 2016, we had approximately 2.7 Bcf of gas volumes hedged for 2016, which represents 10% of our 2016 estimated production, assuming the midpoint of our first quarter 2016 production guidance is held constant for the remainder of the year. 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.

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 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 recently requested that we post collateral to support certain of the bonds that are issued on our behalf. We are currently evaluating various options for posting the requested collateral, however, given the effect of current commodity prices on our creditworthiness and the unwillingness of the surety companies to post bonds without the requisite collateral, we cannot assure you that we will be able to satisfy current or 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 our agreements with the surety companies, which in turn could cause a cross-default under our bank credit facility and potentially the indenture governing our 10% senior secured notes.

We may be required to provide letters of credit to support the additional collateral or bonding requirements requested by the BOEM or the surety companies. Such letters of credit would likely be issued under our bank credit facility and would reduce the amount of borrowings available under such facility in the amount of any such letter of credit obligations. We can provide no assurance that we can continue to obtain bonds or other surety in all cases given these new expenses, and if we are unable to obtain the additional required bonds 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 cancelled or otherwise impose monetary 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 Coast Basin where approximately 40% 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 40% 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, 2015, approximately 40% of our production and approximately 25% 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.

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 2015 production, excluding the impact from successful exploration wells which are not included in the prior year reserve report, was approximately 31% lower than amounts projected in our 2014 reserve report as a result of the Oklahoma Divestiture. We cannot assure you that these differences will not be material in the future.

Approximately 42% of our estimated proved reserves at December 31, 2015 are undeveloped and 20% 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, 2015 are based on twelve-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, 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 bank credit facility contains 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 and technical personnel. 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 beginning of the month average of oil and natural gas prices 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 further write down 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 $266.6 million during the year ended December 31, 2015. Utilizing current strip prices for oil and gas prices for the first quarter of 2016 and projecting the effect on the estimated future net cash flows from our estimated proved reserves as of March 31, 2016, we expect to recognize an additional ceiling test write-down of $20 million to $40 million in the first quarter of 2016.

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;
- 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 “Notices to Lessees and Operators”,("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, a moratorium on the use of the technique. Several proposals have been submitted to Congress that, if implemented, would subject all hydraulic fracturing to regulation under the Safe Drinking Water Act. Further, the USEPA is conducting a scientific study to investigate the possible relationships between hydraulic fracturing and drinking water, and the draft results were released for public and peer review in June 2015. In addition, in February 2014, the USEPA issued final guidance for underground injection permits that regulate hydraulic fracturing using diesel fuel, where the USEPA has permitting authority under the Safe Drinking Water Act. This guidance eventually could encourage other regulatory authorities to adopt permitting and other restrictions on the use of hydraulic fracturing. In May 2014, the USEPA issued an advance notice of proposed rulemaking under the Toxic Substances Control Act to obtain data on chemical substances and mixtures used in hydraulic fracturing and expects to publish a Notice of Proposed Rulemaking on the subject in December 2016. In April 2015, the USEPA proposed regulations under the federal Clean Water Act to impose pretreatment standards on wastewater discharges associated with hydraulic fracturing activities and projects issuance of final rules on the subject in August 2016. The USEPA has also promulgated rules to limit air emissions from many hydraulically fractured natural gas wells. The new regulations will require use of equipment to capture gases that come from the well during the drilling process (so-called green completions). Other new requirements mandate tighter standards for emissions associated with gas production, storage and transport. In addition, the BLM finalized rules in March 2015 that impose new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands including, for example, notice to and pre-approval by the BLM of the proposed hydraulic fracturing activities; development and pre-approval by the BLM of a plan for managing and containing flowback fluids and produced water recovered during the hydraulic fracturing process; implementation of measures designed to protect usable water from hydraulic fracturing activities; and public disclosure of the chemicals used in the hydraulic fracturing fluid (with the exception of certain proprietary information). The U.S. District Court of Wyoming temporarily stayed implementation of this rule, but the BLM has appealed to the Tenth Circuit to overturn the stay.

A number of states, including Louisiana, Oklahoma and Texas, have required operators or service companies to disclose chemical components in fluids used for hydraulic fracturing. Some states have also imposed, or are considering, more stringent regulation of oil and natural gas exploration and production activities involving hydraulic fracturing by, among other things, promulgating well completion requirements, imposing controls on storage, recycling and disposal of flowback fluids, and increasing reporting obligations. In addition, concerns related to the impacts from hydraulic fracturing have led several states and localities to ban new natural gas development or to impose moratoria on use of hydraulic fracturing in various sensitive areas including some areas overlying the Marcellus Shale. Similar action could be taken to preclude or limit natural gas development in other locations.

Recent seismic events have been observed in some areas (including Oklahoma, Ohio and 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 Oklahoma, Ohio and 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. Among other things, in the absence of new federal legislation, the USEPA promulgated regulations imposing reporting and other requirements on sources of significant emissions of greenhouse gases. 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 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 the final outcome of the USEPA's study or the requirements of any additional federal, state or local legislation or regulation regarding hydraulic fracturing, management of drilling fluids, well integrity requirements or climate change, any new 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

- 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.

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.

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 2015, the sales price of our stock ranged from a low of $0.31 per share (on December 22, 2015) to a high of $3.83 per share (on January 2, 2015). 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. We can avoid delisting under this requirement if, during the six month period following receipt of the notice from the New York Stock Exchange, on the last trading-day of any calendar month, our common stock has a closing share price of at least $1.00 and an average closing share price of at least $1.00 over the 30 trading-day period ending on the last trading-day of that month. Under the New York Stock Exchange rules, our common stock will continue to be listed on the New York Stock Exchange during this six month period, subject to our compliance with other listing requirements.

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 have submitted a business plan to the New York Stock Exchange demonstrating how, within the next eighteen months, we intend to regain compliance with the continued listing standards set forth in Section 802.01B of the Listed Company Manual. We intend to continue to work with the New York Stock Exchange to attempt to comply with all continued listing standards. Assuming that the New York Stock Exchange accepts the plan, we will be subject to quarterly monitoring for compliance with the business plan and our common stock will continue to trade on the New York Stock Exchange during the eighteen month period, subject to our compliance with other New York Stock Exchange continued listing requirements. The New York Stock Exchange 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 its 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 our bank credit facility, 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 our bank credit facility currently restrict us from paying cash dividends on our Series B preferred stock and we plan to suspend the dividend 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 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 bank credit facility.

If in the future we are permitted to pay such cash dividends under the terms of our existing debt agreements, including our bank credit facility, 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 our bank credit facility, the indenture governing our 10% senior notes, or the indenture governing the 10% senior secured 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 1,495,000 shares of Series B Preferred Stock, which are presently convertible into 5,147,734 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, 2015, we had reserved approximately 1.4 million shares of common stock for issuance under outstanding options and approximately 5.1 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 4.3 million shares in connection with the private Exchange Offering that will be 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 by our bank credit facility, the indenture governing the 10% senior secured 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**

PetroQuest 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. Management believes that the ultimate disposition of all uninsured or unindemnified matters resulting from existing litigation will not have a material adverse effect on PetroQuest's business or financial position.

Item 4. **Mine Safety Disclosures**

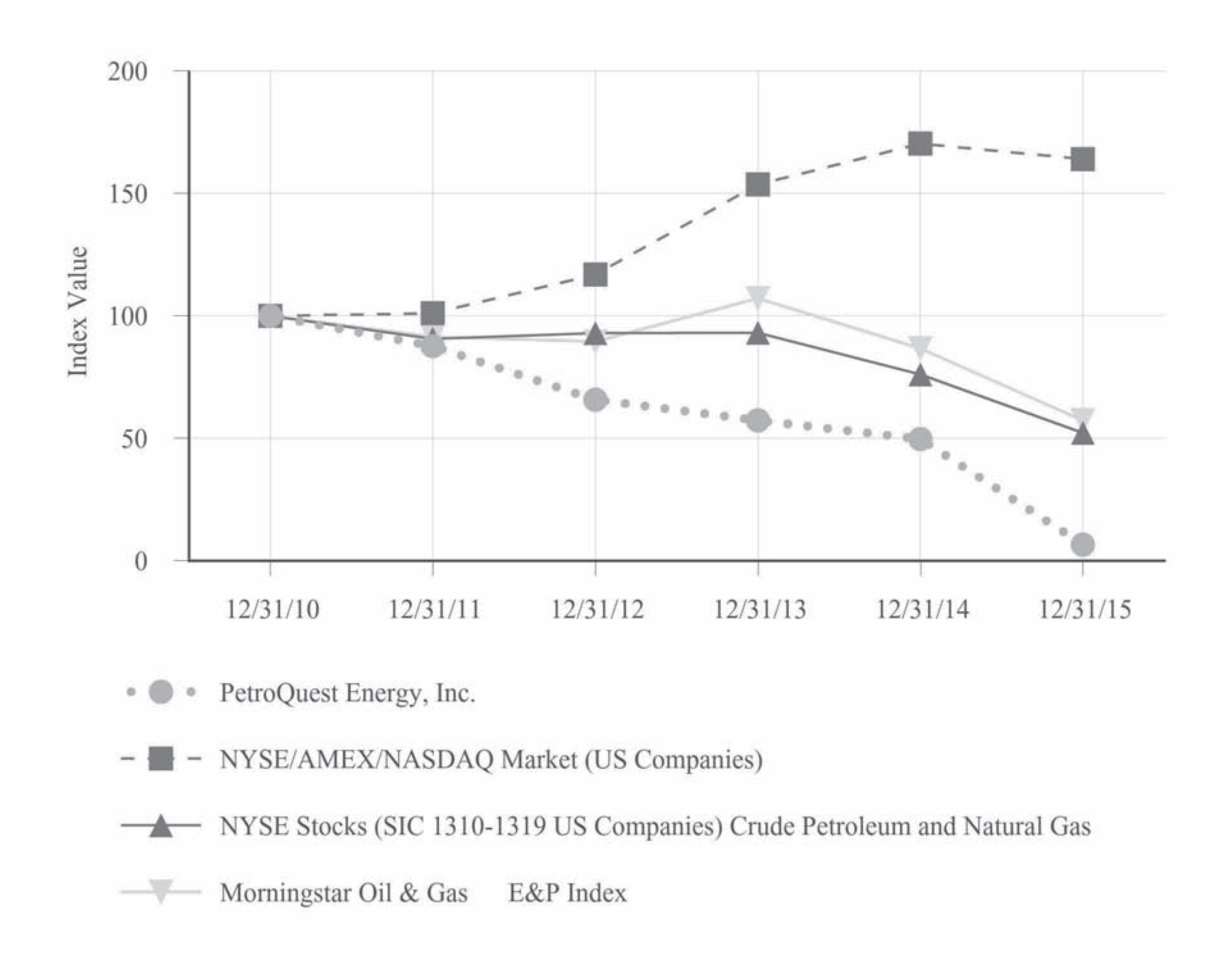
Not applicable.

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, 2015.

Comparison of 5 Year Cumulative Total Return
Assumes Initial Investment of $100
December 31, 2015



	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
12/31/2010	$100.00	$100.00	$100.00	$100.00
12/31/2011	87.65	101.04	90.62	91.44
12/31/2012	65.74	116.84	92.98	89.44
12/31/2013	57.37	153.61	93.07	107.19
12/31/2014	49.67	170.23	76.10	86.70
12/31/2015	6.64	163.89	52.25	57.23

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:

2014	High	Low
1st Quarter	$ 5.93	$ 3.66
2nd Quarter	7.82	5.17
3rd Quarter	7.76	5.13
4th Quarter	5.66	3.15
2015		
1st Quarter	$ 3.83	$ 1.95
2nd Quarter	2.74	1.70
3rd Quarter	1.99	1.05
4th Quarter	1.51	0.31

As of February 26, 2016, there were 252 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 bank credit facility, the indenture governing the 10% senior secured 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, 2015.

	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, 2015	5,049	$ 1.35	—	—
November 1—November 30, 2015	252,157	$ 1.08	—	—
December 1—December 31, 2015	—	$ —	—	—

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

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, 2015 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,				
	2015 (1)	2014	2013	2012 (2)	2011 (3)
	(in thousands except per share and per Mcfe data)				
Average sales price per Mcfe	$ 3.39	$ 5.19	$ 4.80	$ 4.17	$ 5.32
Revenues	115,969	225,021	182,804	141,433	160,486
Net income (loss) available to common stockholders	(299,929)	26,051	8,943	(137,218)	5,409
Net income (loss) available to common stockholders per share:					
Basic	(4.61)	0.39	0.14	(2.20)	0.08
Diluted	(4.61)	0.39	0.14	(2.20)	0.08
Oil and gas properties, net	165,952	683,812	581,242	333,946	405,351
Total assets	379,319	786,108	660,018	430,647	512,819
Long-term debt	347,008	420,213	417,828	147,244	146,653
Stockholders' equity	(163,067)	136,909	99,095	87,591	222,390

(1) The year ended December 31, 2015 includes a pre-tax ceiling test write-down of $266.6 million.
(2) The year ended December 31, 2012 includes a pre-tax ceiling test write-down of $137.1 million.
(3) The year ended December 31, 2011 includes a pre-tax ceiling test write-down of $18.9 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, the Gulf Coast Basin and Oklahoma. 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. 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.

We have successfully diversified into onshore, longer life basins through a combination of selective acquisitions and drilling activity, partially offset by our recent asset divestiture in Oklahoma as discussed below. As a result of our transition to lower-risk, longer life basins, we have realized a 95% drilling success rate on 913 gross wells drilled over the last 10 years. Comparing 2015 metrics with those in 2003, the year we implemented our diversification strategy, we have grown production by 254% and estimated proved reserves by 114%.

Balance Sheet Restructuring

In response to the decline in commodity prices that began in late 2014, and has continued throughout 2015 and into 2016, we have initiated the following steps designed to enhance liquidity and reduce indebtedness:

- Sold the majority of our interests in the Woodford and Mississippian Lime (the "Oklahoma Divestiture") in June 2015 for $280 million;

- Repaid all borrowings outstanding under our bank credit facility with a portion of the net proceeds from the Oklahoma Divestiture;

- Reduced capital expenditures during 2015 by 67%, as compared to 2014;

- Approved a 2016 capital expenditure budget down 65% from 2015 spending;

- Completed an Exchange Offering (as described below) in February 2016 that reduced indebtedness by $69.7 million and extended the maturity on $144.7 million of indebtedness from September 2017 to February 2021; and

- Announced plans to suspend the dividend on our Series B Preferred Stock beginning with the April 2016 payment, which will save $5.1 million annually.

As a result of the actions outlined above, we have reduced our total indebtedness from $420.2 million at December 31, 2014 to $280.3 million as of the date of this report. Most recently, we completed a private exchange offering whereby participating bondholders exchanged approximately $214.4 million of 10% Senior Notes due 2017 for approximately $53.6 million in cash, approximately $144.7 million of our newly issued 10% Senior Secured Second Lien Notes due 2021 and approximately 4.3 million shares of our common stock (the "Exchange Offering"). As a result of the Exchange Offering, we reduced our annual fixed charges by $7 million and eliminated or extended the maturity date on 61% of our $350 million of indebtedness as of December 31, 2015. After completion of the Exchange Offering, we have $280.3 million of total indebtedness with $135.6 million maturing in September 2017 and $144.7 million maturing in February 2021.

In response to the impact that the decline in commodity prices has had on our cash flow, our 2016 capital expenditures, which include capitalized interest and overhead but exclude acquisitions, are expected to range between $20 million and $25 million 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 13% of such reserves, we expect to be able to control the timing of a substantial portion of our capital investments. We also plan to maintain our commodity hedging program and, as in prior years, we may continue to opportunistically dispose of certain assets or enter into joint venture arrangements to provide additional liquidity. In addition, we plan to suspend the quarterly dividend on our outstanding Series B Preferred Stock beginning with the dividend payment in April 2016 (which will save $5.1 million annually), reduce our cash costs by 25% from 2015 levels and consider additional options to refinance our remaining $135.6 million of 10% Senior Notes due 2017.

Oklahoma Divestiture:

On June 4, 2015, we completed the sale of a majority of our interests in the Woodford and Mississippian Lime (the "Sold Assets") for $280 million, subject to customary post-closing purchase price adjustments, effective January 1, 2015. At closing, we 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, we entered into a Contract Operating Services Agreement whereby we will retain a minimal working interest in the Sold Assets and will provide certain services as a contract operator for a period of one year from the closing date of the sale, subject to renewal for two additional one-year terms.

At December 31, 2014, the estimated proved reserves attributable to the Sold Assets totaled approximately 227.2 Bcfe. 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 divestiture of the Sold Assets 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, we 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.

Fleetwood Joint Venture

In June 2014, we entered into a joint venture in Louisiana for an aggregate purchase price of $24 million. The assets acquired under the joint venture include an average 37% working interest in an approximately 30,000 acre leasehold position in Louisiana and exclusive rights, along with our joint venture partner, to a 200 square mile proprietary 3D survey which has generated several conventional and shallow non-conventional oil focused prospects.

The purchase price was comprised of $10 million in cash and $14 million in cash funding for future drilling, completion and lease acquisition costs. At December 31, 2015, $4.4 million of drilling carry remained outstanding which was paid to our joint venture partner in connection with the terms of the agreement during February 2016.

Gulf of Mexico Acquisition

On July 3, 2013, we closed the Gulf of Mexico Acquisition for an aggregate cash purchase price of $188.8 million, reflecting an effective date of January 1, 2013. The Gulf of Mexico Acquisition was financed with the issuance of an additional $200 million in aggregate principal amount of our 10% Senior Notes due 2017. The acquired assets included 16 gross wells located on seven platforms.

The Gulf of Mexico Acquisition added 30.5 Bcfe of estimated proved reserves as of December 31, 2013 and increased our net acreage position in the Gulf Coast Basin by 23%. See "Note 2 - Acquisition & Divestitures" in Item 8. Financial Statements and Supplementary Data for additional details related to this transaction.

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 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 average price using beginning of the month pricing 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.

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 oil and natural gas and OPIS Mt. Bellevue pricing for natural gas liquids. 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 OPIS Mt. Bellevue prices 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 and OPIS Mt. Bellevue prices at which the hedges will be settled. At December 31, 2015, our derivative instruments were designated effective cash flow hedges.

Estimating the fair value of derivative instruments requires valuation calculations incorporating estimates of future NYMEX and OPIS Mt. Bellevue 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.

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, 2015	2014	2013
Production:			
Oil (Bbls)	528,529	802,509	680,980
Gas (Mcf)	25,501,851	31,027,671	29,225,843
Ngl (Mcfe)	5,487,239	7,482,310	4,754,223
Total Production (Mcfe)	34,160,264	43,325,035	38,065,946
Sales:			
Total oil sales	$ 26,532,240	$ 78,176,377	$ 70,476,065
Total gas sales	75,070,130	114,613,267	87,449,370
Total ngl sales	14,367,024	32,231,090	24,878,243
Total oil and gas sales	$ 115,969,394	$ 225,020,734	$ 182,803,678
Average sales prices:			
Oil (per Bbl)	$ 50.20	$ 97.41	$ 103.49
Gas (per Mcf)	2.94	3.69	2.99
Ngl (per Mcfe)	2.62	4.31	5.23
Per Mcfe	3.39	5.19	4.80

The above sales and average sales prices include increases (reductions) to revenue related to the settlement of gas hedges of $15,940,000, ($4,237,000) and $1,098,000, oil hedges of $644,000, $897,000 and ($232,000), and Ngl hedges of $530,000, $296,000 and $61,000 for the twelve months ended December 31, 2015, 2014 and 2013, respectively.

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 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. As a result of the current low commodity price environment, our 2016 capital expenditures budget will be significantly lower as compared to 2015. We expect our total production in 2016 to generally approximate 2015 as a result of several recompletions in the Gulf Coat Basin and our limited drilling program in East Texas.

Gas production during the year ended December 31, 2015 decreased 18% from the 2014 period. The decrease in gas production was due to the Oklahoma Divestiture and normal production declines at our Gulf Coast field, partially offset by the successful drilling program in our Carthage field and the completion of our Thunder Bayou discovery. As a result of a scheduled recompletion of our Thunder Bayou discovery and our limited drilling program in East Texas, we expect our 2016 average daily gas production to generally approximate 2015.

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. As a result of normal production declines at certain of our legacy Gulf Coast fields, we expect our average daily oil production to decrease during 2016 as compared to 2015.

Ngl production during the year ended December 31, 2015 decreased 27% from the 2014 period due to the 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. As a result of the decrease in drilling activity planned during 2016 and the divestiture of our liquids rich Oklahoma wells, we expect our daily Ngl production for 2016 to decrease compared to that of 2015.

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 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 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. We expect lease operating expenses during 2016 to decrease as compared to 2015 expenses on an absolute value basis and increase on a per unit basis as a result of the full year effect of the Oklahoma Divestiture.

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. As a result of the current commodity pricing environment, we expect a decrease in our total and per unit production taxes during 2016 as compared to 2015.

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. We expect general and administrative expenses to decrease further in 2016.

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 current year ceiling test write-downs. As a result of these write-downs, we expect our DD&A rate for 2016 to be lower than the rate during 2015.

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. See Note 12, "Ceiling Test" for further discussion of the ceiling test write-down. Utilizing current strip prices for oil and gas prices for the first quarter of 2016 and projecting the effect on the estimated future net cash flows from our estimated proved reserves as of March 31, 2016, we expect to recognize an additional ceiling test write-down of $20,000,000 to $40,000,000 during the first quarter of 2016.

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 Oklahoma Divestiture. As a result of the consummation of the Exchange Offer described in "Liquidity and Capital Resources - Sources of Capital: Debt" below, we expect interest expense for 2016 to decrease compared to 2015.

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 cumulative three-year 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.

Comparison of Results of Operations for the Years Ended December 31, 2014 and 2013

Net income available to common stockholders totaled $26,051,000 and $8,943,000 for the years ended December 31, 2014 and 2013, respectively. The primary fluctuations were as follows:

Production Total production increased 14% during the year ended December 31, 2014 as compared to the 2013 period. The increase in total production was due primarily to a full year of production from the wells acquired in the Gulf of Mexico Acquisition, which closed on July 3, 2013, as well as our successful drilling programs in our Carthage field and the liquids rich portion of our Oklahoma acreage position. Partially offsetting these increases were decreases in production due to normal production declines at our dry gas Oklahoma fields as well as certain of our legacy Gulf Coast fields.

Gas production during the year ended December 31, 2014 increased 6% from the 2013 period. The increase in gas production was due primarily to our successful drilling program in our Carthage field as well as a full year of production from the wells acquired in the Gulf of Mexico Acquisition. Partially offsetting these increases were decreases in gas production due to normal production declines at our dry gas Oklahoma fields as well as certain of our legacy Gulf Coast fields.

Oil production during the year ended December 31, 2014 increased 18% as compared to the 2013 period due primarily to a full year of production from the wells acquired in the Gulf of Mexico Acquisition. Partially offsetting this increase were decreases as a result of continued normal production declines in certain of our legacy Gulf Coast fields.

Ngl production during the year ended December 31, 2014 increased 57% from the 2013 period due to the successful drilling programs in the liquids rich portion of our Oklahoma acreage position and in our Carthage field. Additionally, Ngl production increased as a result of added production from the wells acquired in the Gulf of Mexico Acquisition. Partially offsetting these increases were decreases as a result of normal production declines at our legacy Gulf Coast fields.

Prices Including the effects of our hedges, average gas prices per Mcf for the year ended December 31, 2014 were $3.69 as compared to $2.99 for the 2013 period. Average oil prices per Bbl for the year ended December 31, 2014 were $97.41 as compared to $103.49 for the 2013 period and average Ngl prices per Mcfe were $4.31 for the year ended December 31, 2014, as compared to $5.23 for the 2013 period. Stated on an Mcfe basis, unit prices received during the year ended December 31, 2014 were 8% higher than the prices received during the 2013 period.

Revenue Including the effects of hedges, oil and gas sales during the twelve months ended December 31, 2014 increased 23% to $225,021,000, as compared to oil and gas sales of $182,804,000 during the 2013 period. The increased revenue during 2014 was primarily the result of increased production during 2014 as well as higher average realized prices for our gas production, which represents the majority of our total production.

Expenses Lease operating expenses for the year ended December 31, 2014 totaled $48,597,000, or $1.12 per Mcfe, as compared to $43,743,000, or $1.15 per Mcfe, during the 2013 period. The decrease in per unit lease operating expenses for the year ended December 31, 2014 is primarily due to increased production from our onshore properties which typically incur lower per unit lease operating expenses.

Production taxes for the year ended December 31, 2014 totaled $5,927,000, or $0.14 per Mcfe, as compared to $3,950,000, or $0.10 per Mcfe, during the 2013 period. The increase in total production taxes was primarily due to increased production from onshore properties subject to severance taxes as well as an increase in Louisiana severance tax rates effective July 2014. 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, 2014 totaled $22,870,000 as compared to $26,512,000 during the 2013 period. General and administrative expenses decreased 14% during the year ended December 31, 2014 primarily due to acquisition-related costs associated with the Gulf of Mexico Acquisition of $4,018,000 incurred during the 2013 period. Included in general and administrative expenses for 2014 are share-based compensation costs, net of amounts capitalized, of $6,808,000, compared to $5,011,000 during the 2013 period. We capitalized $12,122,000 of general and administrative costs during the year ended December 31, 2014 as compared to $13,342,000 during the comparable 2013 period.

DD&A expense on oil and gas properties for the year ended December 31, 2014 totaled $86,406,000, or $1.99 per Mcfe, as compared to $69,357,000, or $1.82 per Mcfe, during the comparable 2013 period. The increase in the per unit DD&A rate is primarily the result of the properties acquired in the Gulf of Mexico Acquisition, which had a higher cost per unit as compared to our overall amortization base.

Interest expense, net of amounts capitalized on unevaluated properties, totaled $29,281,000 during the year ended December 31, 2014, as compared to $21,886,000 during 2013. During the year ended December 31, 2014, our capitalized interest totaled

$9,999,000 as compared to $6,570,000 during the 2013 period. The increase in interest expense was a result of the issuance of an additional $200 million of 10% senior notes in 2013, which were used to finance the Gulf of Mexico Acquisition.

Income tax expense (benefit) during the year ended December 31, 2014 totaled ($2,941,000), as compared to $320,000 during the 2013 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 during 2012, we have incurred a cumulative three-year 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 $33,295,000 as of December 31, 2014.

Liquidity and Capital Resources

We have financed our acquisition, exploration and development activities to date principally through cash flow from operations, bank borrowings, issuances of equity and debt securities, joint ventures and sales of assets. At December 31, 2015, we had a working capital surplus of $50.5 million compared to a deficit of $80.2 million at December 31, 2014. The improvement in our working capital is the result of proceeds received from the Oklahoma Divestiture, partially offset by the full repayment of our bank credit facility. Since we operate the majority of our drilling activities, we have the ability to reduce our capital expenditures to manage our working capital and liquidity position. In response to the impact that the decline in commodity prices has had, and is expected to continue to have, on our cash flow, our 2016 capital expenditures budget has been significantly reduced as compared to 2015 and we plan to fund it through cash flow from operations and cash on hand. To the extent additional capital is required, we may utilize sales of equity or debt securities, evaluate the sale of additional assets, enter into joint venture arrangements or reduce our capital expenditure budget to manage our liquidity position. In addition, we plan to suspend the quarterly dividend on our outstanding Series B Preferred Stock beginning with the dividend payment in April 2016 (which will save $5.1 million annually), reduce our cash costs by 25% from 2015 levels and consider additional options to refinance our remaining $135.6 million of 10% Senior Notes due 2017.

As of December 31, 2015, we had $148 million of cash on hand and had no borrowings outstanding under our bank credit facility. We currently have $42 million of availability under our bank credit facility, subject to compliance with the financial covenants thereunder, which, based on our expectations for the first quarter of 2016, will effectively limit the availability to 25% of the aggregate commitment of the lenders, or $10.5 million.

Prices for oil and natural gas are subject to many factors beyond our control such as weather, the overall condition of the global financial markets and economies, relatively minor changes in the outlook of supply and demand, and the actions of OPEC. Oil and natural gas prices have a significant impact on our cash flows available for capital expenditures and our ability to borrow and raise additional capital. The amount we can borrow under our bank credit facility is subject to periodic re-determination based in part on changing expectations of future prices. Lower prices may also reduce the amount of oil and natural gas that we can economically produce. Lower prices and/or lower production may decrease revenues, cash flows and the borrowing base under the bank credit facility, thus reducing the amount of financial resources available to meet our capital requirements. Lower prices and reduced cash flow may also make it difficult to incur debt, including under our bank credit facility, because of the restrictive covenants in the indenture governing the 10% senior secured notes. See "Source of Capital: Debt" below. Our ability to comply with the covenants in our debt agreements is dependent upon the success of our exploration and development program and upon factors beyond our control, such as oil and natural gas prices.

Source of Capital: Operations

Net cash flow from operations decreased from $178.2 million during the year ended December 31, 2014 to $30.1 million during the 2015 period. The decrease in operating cash flow during 2015 as compared to 2014 was primarily attributable to decreases in oil and gas revenues as well as the timing of payment of payables based on increased operational activity.

Source of Capital: Debt

On August 19, 2010, the Company issued $150 million in principal amount of its 10% Senior Notes due 2017 and on July 3, 2013, the Company issued an additional $200 million in principal amount of its 10% Senior Notes due 2017 (collectively, the "Old Notes"). The Old Notes are guaranteed by certain of PetroQuest's subsidiaries. The subsidiary guarantors are 100% owned by PetroQuest and all guarantees are full and unconditional and joint and several. PetroQuest has no independent assets or operations and the subsidiaries not providing guarantees are minor, as defined by the rules of the Securities and Exchange Commission.

Interest on the Old Notes is payable semi-annually on March 1 and September 1. At December 31, 2015, $11.7 million had been accrued in connection with the March 1, 2016 interest payment (which amount has been reduced to $4.5 million as a result of the Exchange Offering), and the Company was in compliance with all of the covenants then contained in the indenture governing the Old Notes.

On February 17, 2016, the Company completed a private offering to exchange (the "Exchange Offering") up to $300 million aggregate principal amount of the Old Notes and related consent solicitation (the "Consent Solicitation") to amend and waive certain provisions of the indenture governing the Old Notes. At the closing, and in satisfaction of the consideration for $214,379,000 in aggregate principal amount of the Old Notes, representing approximately 61% of the outstanding aggregate principal amount of Old Notes, validly tendered (and not validly withdrawn) in the Exchange Offering, the Company (i) paid approximately $53.6 million of cash, (ii) issued $144,674,000 aggregate principal amount of its newly issued 10% senior secured notes and (iii) issued 4,287,580 shares of its common stock.

The indenture governing the 10% senior secured notes contains affirmative and negative covenants that, among other things, limit the ability of the Company and the subsidiary guarantors of the 10% senior secured 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 10% senior secured notes are fully and unconditionally guaranteed on a senior basis by certain wholly-owned subsidiaries of the Company.

The Company will pay 10% interest per annum on the principal amount of the 10% senior secured notes, semi-annually in arrears on February 15 and August 15 of each year.

The 10% senior secured notes are secured 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 Credit 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 10% senior secured notes and the guarantees are contractually subordinated to liens that secure the Credit Agreement and certain other permitted indebtedness. Consequently, the 10% senior secured notes and the guarantees will be effectively subordinated to the Credit Agreement and such other indebtedness to the extent of the value of such assets.

As a result of the Consent Solicitation, the indenture governing the Old Notes was amended such that substantially all of the restrictive covenants were eliminated or waived.

The Company and PetroQuest Energy, L.L.C. (the "Borrower") have a Credit Agreement (as amended, the "Credit Agreement") with JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A., Capital One, N.A., IberiaBank, Bank of America, N.A. and The Bank of Nova Scotia. The Credit Agreement provides the Company with a $300 million revolving credit facility that permits borrowings based on the commitments of the lenders and the available borrowing base as determined in accordance with the Credit Agreement. The Credit Agreement also allows the Company to use up to $25 million of the borrowing base for letters of credit. The credit facility matures on the earlier of June 4, 2020 or February 19, 2017 if any portion of the Old Notes remain outstanding as of such date which has not been refinanced with either permitted refinancing debt or permitted second lien debt with a maturity date no earlier than 180 days after June 4, 2020, all as defined in the Credit Agreement. As of December 31, 2015 the Company had no borrowings outstanding under (and no letters of credit issued pursuant to) the Credit Agreement.

The borrowing base under the Credit Agreement is determined by March 31 and September 30 of each year and based upon the valuation of the reserves attributable to the Company's oil and gas properties as of January 1 and July 1 of each year. As of December 31, 2015, the borrowing base was $55 million (subject to the aggregate commitments of the lenders then in effect and our compliance with the financial covenants thereunder). During January 2016, the borrowing base and the aggregate commitments of the lenders were reduced to $42 million. Based on the Company's expectations for the first quarter of 2016, the Company anticipates that, pursuant to the applicable financial covenants the Company's utilization of the borrowing base will be limited to 25% of the aggregate commitments of the lenders, or $10.5 million. The next scheduled borrowing base redetermination is scheduled to occur by March 31, 2016 with additional interim redeterminations to occur on July 31 and December 31 of each year, commencing on July 31, 2016. The Company or the lenders may request two additional borrowing base re-determinations each year. Each time the borrowing base is to be re-determined, the administrative agent under the Credit Agreement will propose a new borrowing base as it deems appropriate in its sole discretion, which must be approved by all lenders if the borrowing base is to be increased, or by lenders holding two-thirds of the amounts outstanding under the Credit Agreement if the borrowing base remains the same or is reduced.

The Credit Agreement is secured by a first priority lien on substantially all of the assets of the Company and its subsidiaries, including a lien on all equipment and at least 90% of the aggregate total value of the Borrower's oil and gas properties. Outstanding balances under the Credit Agreement bear interest at the alternate base rate ("ABR") plus a margin (based on a sliding scale of 1.0% to 2.0% depending on total commitments) or the adjusted LIBO rate ("Eurodollar") plus a margin (based on a sliding scale of 2.0% to 3.0% depending on total commitments). The alternate base rate is equal to the highest of (i) the JPMorgan Chase prime rate, (ii) the Federal Funds Effective Rate plus 0.5% or (iii) the adjusted LIBO rate (subject to a floor of 0.0%) plus 1%. For the purposes of the definition of alternate base rate only, the adjusted LIBO rate for any day is based on the LIBO Rate at approximately

11:00 a.m. London time on such day. For all other purposes, the adjusted LIBO rate is equal to the rate at which Eurodollar deposits in the London interbank market for one, two, three or six months (as selected by the Company) are quoted, as adjusted for statutory reserve requirements for Eurocurrency liabilities. Outstanding letters of credit are charged a participation fee at a per annum rate equal to the margin applicable to Eurodollar loans, a fronting fee and customary administrative fees. In addition, the Company pays commitment fees based on a sliding scale of 0.375% to 0.5% depending on total commitments.

The Company and its subsidiaries are subject to certain restrictive financial covenants under the Credit Agreement, including (i) a maximum ratio of total debt to EBITDAX, determined on a rolling four quarter basis, of (a) if the Company has unused availability greater than or equal to 75% of the aggregate commitments of the Lenders at all times during the consecutive three month period prior to and including the date of each fiscal quarter end, the maximum ratio of total debt to EBITDAX is 5.0 to 1.0 as of the last day of the fiscal quarter ending March 31, 2016, 5.5 to 1.0 as of the last day of the fiscal quarter ending June 30, 2016 and 5.75 to 1.0 as of the last day of the fiscal quarters ending September 30, 2016 and December 31, 2016, with in each case the amount of total debt for such quarterly period reduced by the amount of unencumbered and unrestricted cash of the Company and cash subject to an account control agreement, (b) if the Company has unused availability of less than 75% of the aggregate commitments of the Lenders at any time during the consecutive three month period prior to and including the date of calculating the ratio, the maximum ratio of total debt to EBITDAX will be 5.75 to 1.00 as of the last day of the fiscal quarters ending March 31, 2016, June 30, 2016 and September 30, 2016 and 5.25 to 1.00 as of the last day of the fiscal quarter ending December 31, 2016, and (c) 5.00 to 1.00 as of the last day of any fiscal quarter ending on or after March 31, 2017 and (ii) a minimum ratio of EBITDAX to total cash interest expense of 1.0 to 1.0, all as defined in the Credit Agreement.

In addition, the Credit Agreement permits a sale of the majority of the Company's remaining oil and gas assets in Oklahoma, provided that such sale is consummated on or prior to March 31, 2016, all of the consideration received in such sale is cash, and the borrowing base will be reduced by $10 million upon the consummation of such sale. The Credit Agreement currently prohibits the Company from declaring and paying dividends on its Series B Preferred Stock.

The Credit 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, 2015, the Company was in compliance with all such covenants contained in the Credit Agreement.

As a result of the impact of the decline in commodity prices, we anticipate that we may exceed the maximum ratio of total debt to EBITDAX financial covenant included in the Credit Agreement as early as the end of the first quarter of 2016, which would require us to seek a waiver or amendment from the lenders. We cannot provide any assurances that we will be able to reach an agreement with the lenders on an amendment or waiver on a timely basis or on satisfactory terms to alleviate any non-compliance with the financial covenants under the Credit Agreement.

Source of Capital: Issuance of Securities

Our shelf registration statement allows us to publicly offer and sell up to $350 million of any combination of debt securities, shares of common and preferred stock, depositary shares and warrants. The registration statement does not provide any assurance that we will or could sell any such securities.

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 January 2013, we sold 50% of our saltwater disposal systems and related surface assets in the Woodford for net proceeds of approximately $10 million. In December 2013, we sold our non-operated Wyoming assets for a cash purchase price of $1.0 million. In September 2014, we sold our Eagle Ford assets for net proceeds of approximately $9.8 million. In 2015, we sold the majority of our Oklahoma assets for net proceeds of approximately $274.1 million as well as our Fort Trinidad and East Haynesville assets for net proceeds of approximately $0.5 million and $0.1 million, respectively.

Use of Capital: Exploration and Development

Our 2016 capital budget, which includes capitalized interest and general and administrative costs, is expected to range between $20 million and $25 million, which from the midpoint of such range, represents a 65% reduction from our 2015 capital expenditures in response to weaker commodity prices. 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 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

On July 3, 2013, we closed the Gulf of Mexico Acquisition for an aggregate cash purchase price of $188.8 million. The acquired assets include 16 gross wells located on seven platforms.

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 or available borrowings under our bank credit facility. We may also utilize sales of equity or debt securities, 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.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2015 (in thousands):

	Total	2016	2017	2018	2019	2020	**After 2020**
10% senior notes (1)	$408,333	$ 35,000	$373,333	$ —	$ —	$ —	$ —
Operating leases (2)	5,245	1,419	1,310	452	422	417	1,225
Asset retirement obligations (3)	42,556	6,015	6,343	1,539	589	23,975	4,095
Acquisition Costs (4)	4,409	4,409	—	—	—	—	—
Total	$460,543	$ 46,843	$380,986	$ 1,991	$ 1,011	$ 24,392	$ 5,320

(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 amounts payable related to the Fleetwood Joint Venture

As a result of the Exchange Offering described above, we reduced our annual fixed charges by $7 million and eliminated or extended the maturity date on 61% of our $350 million of indebtedness as of December 31, 2015. After completion of the Exchange Offering, we have $280.3 million of total indebtedness with $135.6 million maturing in September 2017 and $144.7 million maturing in February 2021.

The following table summarizes our contractual obligations as of the date of this report (in thousands):

	Total	2016	2017	2018	2019	2020	**After 2020**
10% senior notes (1)	$156,454	$ 7,271	$149,183	$ —	$ —	$ —	$ —
10% senior secured notes (1)	212,191	7,756	14,468	14,468	14,468	14,468	146,563
Operating leases (2)	5,245	1,419	1,310	452	422	417	1,225
Asset retirement obligations (3)	42,556	6,015	6,343	1,539	589	23,975	4,095
Total	$416,446	$ 22,461	$171,304	$ 16,459	$ 15,479	$ 38,860	$ 151,883

(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.

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

We experience market risks primarily in two areas: interest rates and 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 2016, 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 $4.9 million decline in our revenues for 2016.

We periodically seek to reduce our exposure to commodity price volatility by hedging a portion of 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, 2015, we received approximately $17.1 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 Credit Agreement requires that the counterparties to our hedge contracts be lenders under the Credit Agreement or, if not a lender under the Credit Agreement, rated A/A2 or higher by S&P or Moody's. Currently, the counterparties to our existing hedge contracts are JPMorgan Chase Bank and The Bank of Nova Scotia, both of whom are lenders under the Credit Agreement. To the extent we enter into additional hedge contracts, we would expect that certain of the lenders under the Credit Agreement would serve as counterparties.

As of December 31, 2015, we had entered into the following gas hedge contract:

Production Period	Instrument Type	Daily Volumes	Weighted Average Price
Natural Gas:			
January 2016 - June 2016	Swap	10,000 Mmbtu	$3.22

During January 2016, we entered into the following additional hedge contract accounted for as a cash flow hedge:

Production Period	Instrument Type	Daily Volumes	Weighted Average Price
Natural Gas:			
July 2016 - December 2016	Swap	5,000 Mmbtu	$2.50

After executing the above transactions, the Company has approximately 2.7 Bcf of gas volumes, at an average price of $2.98 per Mcf hedged for 2016, which represents 10% of our 2016 estimated production assuming the midpoint of our first quarter 2016 production guidance is held constant for the remainder of the year.

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, 2015 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, 2015. 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.

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, 2015 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, 2015 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, 2015.

March 4, 2016

/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

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, 2015, 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, 2015, 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, 2015 and 2014, 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, 2015 and our report dated March 4, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

New Orleans, Louisiana
March 4, 2016

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 18, 2016, 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, 2015 and 2014
Consolidated Statements of Operations for the three years ended December 31, 2015
Consolidated Statements of Comprehensive Income (Loss) for the three years ended December 31, 2015
Consolidated Statements of Cash Flows for the three years ended December 31, 2015
Consolidated Statements of Stockholders' Equity for the three years ended December 31, 2015
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.

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).
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 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).
3.3	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).
3.4	Certificate of Domestication of Optima Petroleum Corporation (incorporated herein by reference to Exhibit 4.4 to Form 8-K filed September 16, 1998).
3.5	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).
3.6	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).
4.1	Rights Agreement dated as of November 7, 2001 between PetroQuest Energy, Inc. and American Stock Transfer & Trust Company, as Rights Agent, including exhibits thereto (incorporated herein by reference to Exhibit 1 to Form 8-A filed November 9, 2001).
4.2	Form of Rights Certificate (incorporated herein by reference to Exhibit C of the Rights Agreement attached as Exhibit 1 to Form 8-A filed November 9, 2001).
4.3	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).
4.5	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).

4.6	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).
4.7	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)
4.8	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).
4.9	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).
4.10	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).
4.11	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).
†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, Tracy Price 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).
†10.4	Form of Restricted Stock Agreement for executive officers (including Charles T. Goodson, Arthur M. Mixon, III, J. Bond Clement, Tracy Price 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, Tracy Price 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, Tracy Price 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, Tracy Price 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, Tracy Price 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, Tracy Price 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	Credit Agreement dated as of October 2, 2008, among PetroQuest Energy, L.L.C., PetroQuest Energy, Inc., JPMorgan Chase Bank, N.A., Calyon New York Branch, Bank of America, N.A., Wells Fargo Bank, N.A., and Whitney National Bank (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed October 6, 2008).
10.17	First Amendment to Credit Agreement dated as of March 24, 2009, among PetroQuest Energy, Inc., PetroQuest Energy, L.L.C., TDC Energy LLC, JPMorgan Chase Bank, N.A., Calyon New York Branch, Bank of America, N.A., Wells Fargo Bank, N.A. and Whitney National Bank (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed March 24, 2009).
10.18	Second Amendment to Credit Agreement dated as of September 30, 2009, among PetroQuest Energy, Inc., PetroQuest Energy, L.L.C., TDC Energy LLC, JPMorgan Chase Bank, N.A., Calyon New York Branch, Bank of America, N.A., Wells Fargo Bank, N.A. and Whitney National Bank (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed October 1, 2009).
10.19	Third Amendment to Credit Agreement dated as of August 5, 2010, among PetroQuest Energy, Inc., PetroQuest Energy, L.L.C., TDC Energy LLC, JPMorgan Chase Bank, N.A., Credit Agricole Corporate and Investment Bank, Bank of America, N.A., Wells Fargo Bank, N.A. and Whitney National Bank (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed on August 6, 2010).
10.20	Fourth Amendment to Credit Agreement dated as of October 3, 2011, among PetroQuest Energy, Inc., PetroQuest Energy, L.L.C., TDC Energy LLC, JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A., Capital One, N.A., Iberiabank and Whitney Bank (incorporated herein by reference to Exhibit 10.1 to the Form 8-K filed on October 4, 2011).
10.21	Fifth Amendment to Credit Agreement dated as of March 29, 2013, among PetroQuest Energy, Inc., PetroQuest Energy, L.L.C., JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A., Capital One, N.A., IBERIABANK and Whitney Bank (incorporated herein by reference to Exhibit 10.1 to the Form 8-K filed on March 29, 2013).
10.22	Sixth Amendment to Credit Agreement dated as of June 19, 2013, among PetroQuest Energy, Inc., PetroQuest Energy, L.L.C., JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A., Capital One, N.A., IBERIABANK and Whitney Bank (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on June 20, 2013).

10.23	Seventh Amendment to Credit Agreement dated as of March 31, 2014, among PetroQuest Energy, Inc., PetroQuest Energy, L.L.C., JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A., Capital One, N.A., Iberiabank, Bank of America, N.A. and The Bank of Nova Scotia (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on March 31, 2014).
10.24	Eighth Amendment to Credit Agreement dated as of September 29, 2014, among PetroQuest Energy, Inc., PetroQuest Energy, L.L.C., JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A., Capital One, N.A., Iberiabank, Bank of America, N.A. and The Bank of Nova Scotia (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on September 30, 2014).
10.25	Ninth Amendment to Credit Agreement dated as of February 26, 2015, among PetroQuest Energy, Inc., PetroQuest Energy, L.L.C., JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A., Capital One, N.A., Iberiabank, Bank of America, N.A. and The Bank of Nova Scotia (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on February 26, 2015).
10.26	Tenth Amendment to Credit Agreement dated as of March 27, 2015, among PetroQuest Energy, Inc., PetroQuest Energy, L.L.C., JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A., Capital One, N.A., Iberiabank, Bank of America, N.A. and The Bank of Nova Scotia (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on March 30, 2015).
10.27	Eleventh Amendment to Credit Agreement dated as of June 4, 2015, among PetroQuest Energy, Inc., PetroQuest Energy, L.L.C., JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A., Capital One, N.A., Iberiabank, Bank of America, N.A. and The Bank of Nova Scotia (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on June 5, 2015).
10.28	Twelfth Amendment to Credit Agreement dated as of September 8, 2015, among PetroQuest Energy, Inc., PetroQuest Energy, L.L.C., TDC Energy LLC, JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A., Capital One, N.A., Iberiabank, Bank of America, N.A. and The Bank of Nova Scotia (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on September 8, 2015).
10.29	Thirteenth Amendment to Credit Agreement dated as of January 25, 2016, among PetroQuest Energy, Inc., PetroQuest Energy, L.L.C., TDC Energy, LLC, JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A., Capital One, National Association, IBERIABANK, Bank of America, N.A. and The Bank of Nova Scotia (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on January 26, 2016).
†10.30	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).
†10.31	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).
†10.32	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).
†10.33	Executive Employment Agreement dated May 8, 2012 between PetroQuest Energy, Inc. and Tracy Price (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed May 10, 2012).
†10.34	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).

†10.35	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).
†10.36	Termination Agreement dated May 8, 2012 between PetroQuest Energy, Inc. and Tracy Price (incorporated herein by reference to Exhibit 10.2 to Form 8-K filed May 10, 2012).
†10.37	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).
†10.38	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, Tracy Price, Edward E. Abels, Jr., William W. Rucks, IV, E. Wayne Nordberg, Michael L. Finch, 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).
†10.39	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).
10.40	Joint Development Agreement dated May 17, 2010, among PetroQuest Energy, L.L.C., a Louisiana limited liability company, WSGP Gas Producing, LLC, a Delaware limited liability company, and NextEra Energy Gas Producing, LLC, a Delaware limited liability company (incorporated herein by reference to Exhibit 10.2 to Form 10-Q filed on August 5, 2010).
*10.41	First Amendment to the Joint Development Agreement dated May 17, 2010, among PetroQuest Energy, L.L.C., a Louisiana limited liability company, WSGP Gas Producing, LLC, a Delaware limited liability company, and NextEra Energy Gas Producing, LLC, a Delaware limited liability company.
10.42	Second Amendment to the Joint Development Agreement dated February 24, 2012, among PetroQuest Energy, L.L.C., a Louisiana limited liability company, WSGP Gas Producing, LLC, a Delaware limited liability company, and NextEra Energy Gas Producing, LLC, a Delaware limited liability company (incorporated herein by reference to Exhibit 10.22 to Form 10-K filed March 5, 2012).
10.43	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).
10.44	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).

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, 2015, as prepared by Ryder Scott Company, L.P.
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

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.

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.

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.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on March 4, 2016.

PETROQUEST ENERGY, INC.

By: /s/ Charles T. Goodson
CHARLES T. GOODSON
Chairman of the Board, President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 4, 2016.

By:	/s/ Charles T. Goodson CHARLES T. GOODSON	Chairman of the Board, President, Chief Executive Officer and Director (Principal Executive Officer)
By:	/s/ J. Bond Clement J. BOND CLEMENT	Executive Vice President, Chief Financial Officer, Treasurer (Principal Financial and Accounting Officer)
By:	/s/ W.J. Gordon, III W.J. GORDON, III	Director
By:	/s/ Michael L. Finch MICHAEL L. FINCH	Director
By:	/s/ Charles F. Mitchell, II, M.D. CHARLES F. MITCHELL, II, M.D.	Director
By:	/s/ E. Wayne Nordberg E. WAYNE NORDBERG	Director
By:	/s/ William W. Rucks, IV WILLIAM W. RUCKS, IV	Director

INDEX TO FINANCIAL STATEMENTS

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, 2015 and 2014, 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, 2015. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of PetroQuest Energy, Inc. at December 31, 2015 and 2014, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, 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, 2015, 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 4, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

New Orleans, Louisiana
March 4, 2016

PETROQUEST ENERGY, INC.
Consolidated Balance Sheets
(Amounts in Thousands)

	December 31, 2015	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	$ 148,013	$ 18,243
Revenue receivable	6,476	16,485
Joint interest billing receivable	49,374	46,778
Derivative asset	1,508	8,631
Other current assets	3,874	6,413
Total current assets	209,245	96,550
Property and equipment:		
Oil and gas properties:		
Oil and gas properties, full cost method	1,310,891	2,222,753
Unevaluated oil and gas properties	12,516	109,119
Accumulated depreciation, depletion and amortization	(1,157,455)	(1,648,060)
Oil and gas properties, net	165,952	683,812
Other property and equipment	11,229	14,953
Accumulated depreciation of other property and equipment	(8,737)	(10,313)
Total property and equipment	168,444	688,452
Other assets, net of accumulated amortization of $3,842 and $3,448, respectively	1,630	1,106
Total assets	$ 379,319	$ 786,108
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable to vendors	$ 97,999	$ 102,954
Advances from co-owners	16,118	12,819
Oil and gas revenue payable	18,911	22,333
Accrued interest and preferred stock dividend	12,795	12,764
Asset retirement obligation	6,015	2,756
Accrued acquisition costs	4,409	17,690
Other accrued liabilities	2,537	5,394
Total current liabilities	158,784	176,710
Bank debt	—	75,000
10% Senior Notes	347,008	345,213
Asset retirement obligation	36,541	52,214
Other long-term liability	53	62
Commitments and contingencies		
Stockholders' equity:		
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 65,641 and 64,721 shares, respectively	66	65
Paid-in capital	290,382	285,957
Accumulated other comprehensive income	947	5,420
Accumulated deficit	(454,463)	(154,534)
Total stockholders' equity	(163,067)	136,909
Total liabilities and stockholders' equity	$ 379,319	$ 786,108

See accompanying Notes to Consolidated Financial Statements.

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

	Year Ended December 31, 2015	2014	2013
Revenues:			
Oil and gas sales	$ 115,969	$ 225,021	$ 182,804
Expenses:			
Lease operating expenses	40,130	48,597	43,743
Production taxes	2,470	5,927	3,950
Depreciation, depletion and amortization	63,497	87,818	71,445
Ceiling test write-down	266,562	—	—
General and administrative	20,777	22,870	26,512
Accretion of asset retirement obligation	3,259	2,958	1,753
Interest expense	33,766	29,281	21,886
	430,461	197,451	169,289
Other income:			
Gain on sale of assets	21,937	—	—
Other income	391	679	654
Derivative income	—	—	233
	22,328	679	887
Income (loss) from operations	(292,164)	28,249	14,402
Income tax expense (benefit)	2,626	(2,941)	320
Net income (loss)	(294,790)	31,190	14,082
Preferred stock dividend	5,139	5,139	5,139
Net income (loss) available to common stockholders	$ (299,929)	$ 26,051	$ 8,943
Earnings per common share:			
Basic			
Net income (loss) per share	$ (4.61)	$ 0.39	$ 0.14
Diluted			
Net income (loss) per share	$ (4.61)	$ 0.39	$ 0.14
Weighted average number of common shares:			
Basic	65,022	64,204	63,054
Diluted	65,022	64,225	63,208

See accompanying Notes to Consolidated Financial Statements.

PETROQUEST ENERGY, INC.

Consolidated Statements of Comprehensive Income (Loss)

(Amounts in Thousands)

	Year Ended December 31,		
	2015	2014	2013
Net income (loss)	$ (294,790)	$ 31,190	$ 14,082
Change in fair value of derivatives, net of income tax (expense) benefit of $2,650, ($3,211) and $309 respectively	(4,473)	6,516	(1,617)
Comprehensive income (loss)	$ (299,263)	$ 37,706	$ 12,465

See accompanying Notes to Consolidated Financial Statements.

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

	Year Ended December 31, 2015	2014	2013
Cash flows from operating activities:			
Net income (loss)	$ (294,790)	$ 31,190	$ 14,082
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Deferred tax expense (benefit)	2,626	(2,941)	320
Depreciation, depletion and amortization	63,497	87,818	71,445
Ceiling test write-down	266,562	—	—
Accretion of asset retirement obligation	3,259	2,958	1,753
Share based compensation expense	4,617	5,248	4,216
Gain on sale of assets	(21,937)	—	—
Amortization costs and other	2,259	2,188	1,473
Non-cash derivative income	—	—	(233)
Payments to settle asset retirement obligations	(2,776)	(3,623)	(3,335)
Changes in working capital accounts:			
Revenue receivable	10,009	10,083	(8,826)
Prepaid drilling and pipe costs	—	(370)	1,221
Joint interest billing receivable	223	(20,276)	15,685
Accounts payable and accrued liabilities	(9,400)	50,243	(12,865)
Advances from co-owners	3,299	11,850	(19,490)
Other	2,657	3,840	(5,592)
Net cash provided by operating activities	30,105	178,208	59,854
Cash flows provided by (used in) investing activities:			
Investment in oil and gas properties	(90,218)	(174,633)	(298,824)
Investment in other property and equipment	(454)	(926)	(1,679)
Sale of oil and gas properties	271,769	11,908	20,400
Net cash provided by (used in) investing activities	181,097	(163,651)	(280,103)
Cash flows provided by (used in) financing activities:			
Net payments for share based compensation	(199)	(75)	(38)
Deferred financing costs	(1,094)	(253)	(320)
Payment of preferred stock dividend	(5,139)	(5,139)	(5,139)
Proceeds from bank borrowings	70,000	17,500	73,000
Repayment of bank borrowings	(145,000)	(17,500)	(48,000)
Proceeds from issuance of 10% Senior Notes	—	—	200,000
Costs to issue 10% Senior Notes	—	—	(5,005)
Net cash provided by (used in) financing activities	(81,432)	(5,467)	214,498
Net increase (decrease) in cash and cash equivalents	129,770	9,090	(5,751)
Cash and cash equivalents, beginning of period	18,243	9,153	14,904
Cash and cash equivalents, end of period	$ 148,013	$ 18,243	$ 9,153
Supplemental disclosure of cash flow information:			
Cash paid during the period for:			
Interest	$ 36,217	$ 37,174	$ 20,101
Income taxes	$ —	$ 270	$ 12

See accompanying Notes to Consolidated Financial Statements.

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, 2012	$ 63	$ 1	$ 276,534	$ 521	$ (189,528)	$ 87,591
Options exercised	—	—	731	—	—	731
Retirement of shares upon vesting of restricted stock	1	—	(1,057)	—	—	(1,056)
Share-based compensation expense	—	—	4,216	—	—	4,216
Issuance of shares under employee stock purchase plan	—	—	287	—	—	287
Derivative fair value adjustment, net of tax	—	—	—	(1,617)	—	(1,617)
Preferred stock dividend	—	—	—	—	(5,139)	(5,139)
Net income	—	—	—	—	14,082	14,082
December 31, 2013	$ 64	$ 1	$ 280,711	$ (1,096)	$ (180,585)	$ 99,095
Options exercised	—	—	1,032	—	—	1,032
Retirement of shares upon vesting of restricted stock	1	—	(1,310)	—	—	(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	$ 65	$ 1	$ 285,957	$ 5,420	$ (154,534)	$ 136,909
Options exercised	—	—	61	—	—	61
Retirement of shares upon vesting of restricted stock	1	—	(452)	—	—	(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	$ 66	$ 1	$ 290,382	$ 947	$ (454,463)	$ (163,067)

See accompanying 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 exploration offices in The Woodlands, Texas and Tulsa, Oklahoma. It is engaged in the exploration, development, acquisition and operation of oil and gas properties in Texas and the Gulf Coast Basin, as well as in Oklahoma.

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.

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 first of the month average twelve-month 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 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.

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. During 2012, a field office servicing the Company's Oklahoma assets was built and is being depreciated over 39 years.

Other Assets

Other assets at December 31, 2015 and 2014 included $1.4 million and $0.7 million, respectively, related to deferred financing costs with respect to the Company's bank credit facility, which are amortized on a straight-line basis over the life of the 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 which 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 realizabilty 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,		
	2015	**2014**	**2013**
Laclede Energy	21%	24%	14%
Shell Trading Co.	18%	30%	35%
Unimark, LLC	17%	14%	14%
BG Group	10%	(a)	(a)

(a) Less than 10 percent

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 cash settlements of hedges are recorded as adjustments to oil and gas sales. Oil and gas revenues include additions (reductions) related to the net settlement of hedges totaling $17.1 million, ($3.0) million and $0.9 million during 2015, 2014 and 2013, respectively.

The Company’s hedges are specifically referenced to NYMEX prices for oil and 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, 2015, the Company's derivative instruments were designated as effective cash flow hedges. See Note 8 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. Early application is not permitted. 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. 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 April 2015, the FASB issued ASU No. 2015-03, "Simplifying the Presentation of Debt Issuance Costs", which changes the presentation of debt issuance costs in financial statements to present such costs as a direct deduction from the related debt liability rather than as an asset. Additionally, in August 2015, the FASB issued ASU No. 2015-15, "Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements", which was issued to clarify the guidance with respect to the presentation of debt issuance costs related to line-of-credit arrangements. ASU 2015-15 clarifies that the SEC staff would not object to an entity deferring and presenting such debt issuance costs as an asset and subsequently amortizing the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. The Company has elected to early adopt this standard effective December 31, 2015. As a result, deferred financing costs, net of accumulated amortization, related to the Company's 10% Senior Notes due 2017 of $3.0 million and $4.8 million as of December 31, 2015 and 2014, respectively, were reclassified from other assets to a direct reduction from the carrying amount of the related debt.

Note 2—Acquisitions and Divestitures

Acquisitions:

Gulf of Mexico

On July 3, 2013, the Company acquired certain shallow water Gulf of Mexico shelf oil and gas properties (the "Acquired Assets"), for an aggregate cash purchase price of $188.8 million, reflecting an effective date of January 1, 2013 (collectively, the "Gulf of Mexico Acquisition"). The Acquired Assets included 16 gross wells located on seven platforms.

The aggregate cash purchase price of the Gulf of Mexico Acquisition was financed with the net proceeds from the sale of $200 million in aggregate principal amount of the Company's 10% Senior Notes due 2017. In connection with the transaction, the Company recorded $5 million of deferred financing costs and incurred $4.0 million of acquisition-related costs, including $2.6 million related to a bridge commitment fee, which were recognized as general and administrative expenses during 2013.

The Gulf of Mexico Acquisition was accounted for under the acquisition method of accounting, which involves determining the fair value of the assets acquired and liabilities assumed. The fair value of proved and unevaluated oil and gas properties was estimated using the income approach based on estimated reserve quantities, costs to produce and develop reserves, and forward prices for oil and gas, which represent Level 2 and Level 3 inputs. Asset retirement obligations were determined in accordance with applicable accounting standards.

The following table summarizes the acquisition date fair values of the net assets acquired (in thousands):

Oil and gas properties	$	192,067
Unevaluated oil and gas properties		12,033
Asset retirement obligations		(15,319)
Net assets acquired	$	188,781

The following unaudited summary pro forma financial information for the twelve month periods ended December 31, 2013 has been prepared to give effect to the Gulf of Mexico Acquisition as if it had occurred on January 1, 2012. The pro forma financial information is not necessarily indicative of the results that might have occurred had the transaction taken place on January 1, 2012 and is not intended to be a projection of future results. Future results may vary significantly from the results reflected in the following unaudited pro forma financial information because of normal production declines, changes in commodity prices, future acquisitions and divestitures, future development and exploration activities and other factors. Amounts are presented in thousands, except per share amounts.

		Twelve Months Ended December 31, 2013
Revenues	$	215,666
Income from Operations		19,858
Net Income available to common stockholders		14,399
Basic Earnings per Share	$	0.22
Diluted Earnings per Share	$	0.22

Fleetwood Joint Venture

In June 2014, we entered into a joint venture in Louisiana for an aggregate purchase price of $24 million. The assets acquired under the joint venture include an average 37% working interest in an approximately 30,000 acre leasehold position in Louisiana and exclusive rights, along with our joint venture partner, to a 200 square mile proprietary 3D survey which has generated several conventional and shallow non-conventional oil focused prospects.

The purchase price was comprised of $10 million in cash and $14 million in cash funding for future drilling, completion and lease acquisition costs. At December 31, 2015, $4.4 million of this drilling carry remained outstanding. The liability is reflected as accrued acquisition costs in the Consolidated Balance Sheet. During February 2016, the Company paid $4.4 million to settle this liability with its joint venture partner in connection with the terms of the agreement.

Divestiture:

On June 4, 2015, the Company completed the sale of a majority of its interests in the Woodford and Mississippian Lime (the “Oklahoma Divestiture”) 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 will retain a minimal working interest in the Sold Assets and will provide certain services as a contract operator for a period of one year from the closing date of the sale, subject to renewal for two additional one-year terms.

At December 31, 2014, the estimated proved reserves attributable to the Oklahoma Divestiture 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 divestiture of the Oklahoma Divestiture 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.

Note 3—Subsequent Event

On January 14, 2016 the Company announced the commencement of a private exchange offer (the "Exchange Offer") and consent solicitation (the "Consent Solicitation") to certain eligible holders for up to $300 million aggregate principal amount of its outstanding 10% Senior Notes due 2017 (the "Old Notes") for up to (i) $75 million in cash, (ii) $202.5 million aggregate principal amount of its newly issued 10% Second Lien Senior Secured Notes due 2021 (the "New Notes"), and (iii) 6 million shares of its common stock. The Exchange Offer and Consent Solicitation were made upon the terms and subject to the conditions set forth in the Confidential Offering Memorandum and Consent Solicitation Statement (the "Offering Memorandum") and related letter of transmittal and consent, each dated January 14, 2016.

The Exchange Offer and Consent Solicitation closed on February 17, 2016, and in satisfaction of the consideration for $214.4 million in aggregate principal amount of the Old Notes, representing approximately 61% of the outstanding aggregate principal amount of Old Notes, validly tendered (and not validly withdrawn) in the Exchange Offer, the Company (i) paid approximately $53.6 million of cash, (ii) issued $144.7 million aggregate principal amount of New Notes and (iii) issued 4,287,580 shares of its common stock. Following the completion of the Exchange Offer, $135.6 million in aggregate principal amount of the Old Notes remain outstanding. The Consent Solicitation eliminates or waives substantially all of the restrictive covenants contained in the indenture governing the Old Notes.

The indenture governing the New Notes contains affirmative and negative covenants that, among other things, limit the ability of the Company and the subsidiary guarantors of the New 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 New Notes are fully and unconditionally guaranteed on a senior basis by certain wholly-owned subsidiaries of the Company.

The Company will pay 10% interest per annum on the principal amount of the New Notes, semi-annually in arrears on February 15 and August 15 of each year.

The New Notes are secured 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 Credit 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 New Notes and the guarantees are contractually subordinated to liens that secure the Credit Agreement and certain other permitted indebtedness. Consequently, the New Notes and the guarantees will be effectively subordinated to the Credit Agreement and such other indebtedness to the extent of the value of such assets.

Note 4—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.

On January 26, 2016, in connection with an amendment to the Company's bank credit facility prohibiting the Company from declaring or paying dividends on the Series B Preferred Stock, the Company announced its intention to suspend the quarterly cash dividend on it 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 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.

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 3.4433 shares of the Company's common stock (which is based on an initial conversion price of approximately $14.52 per share of common stock, subject to 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.

Note 5—Earnings Per Share

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

For the Year Ended December 31, 2015	Loss(Numerator)	Shares (Denominator)	Per Share Amount
BASIC EPS			
Net loss available to common stockholders	$ (299,929)	65,022	$ (4.61)
Stock options	—	—	
Attributable to participating securities	—	—	
DILUTED EPS	$ (299,929)	65,022	$ (4.61)
For the Year Ended December 31, 2014	Income (Numerator)	Shares (Denominator)	Per Share Amount
Net income available to common stockholders	$ 26,051	64,204	
Attributable to participating securities	(855)	—	
BASIC EPS	$ 25,196	64,204	$ 0.39
Net income available to common stockholders	$ 26,051	64,204	
Effect of dilutive securities:			
Stock options	—	21	
Attributable to participating securities	(854)	—	
DILUTED EPS	$ 25,197	64,225	$ 0.39
For the Year Ended December 31, 2013	Income (Numerator)	Shares (Denominator)	Per Share Amount
Net income available to common stockholders	$ 8,943	63,054	
Attributable to participating securities	(257)	—	
BASIC EPS	$ 8,686	63,054	$ 0.14
Net income available to common stockholders	$ 8,943	63,054	
Effect of dilutive securities:			
Stock options	—	154	
Attributable to participating securities	(256)	—	
DILUTED EPS	$ 8,687	63,208	$ 0.14

An aggregate of 0.3 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 5.1 million shares were not included in the computation of diluted earnings per share for 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 5.1 million shares during 2014 and 2013 were not included in the computation of diluted earnings per share because the inclusion would have been anti-dilutive. Options to purchase 1.0 million and 1.2 million shares of common stock were outstanding during the year ended December 31, 2014 and 2013, respectively, 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 6—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, 2015, 2014 and 2013 is as follows (in thousands):

	Year Ended December 31,		
	2015	2014	2013
Stock options:			
Incentive Stock Options (share settled)	$ 243	$ 573	$ 310
Non-Qualified Stock Options (share settled)	71	171	222
Restricted stock (share settled)	4,303	4,504	3,684
Cash settled stock units	(439)	3,094	1,611
Share-based compensation	$ 4,178	$ 8,342	$ 5,827

During the years ended December 31, 2014 and 2013, the Company capitalized $1.5 million and $0.8 million 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, 2015, 2014 and 2013, the Company recorded income tax benefits of approximately $1.5 million, $2.3 million and $1.8 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 stock

At December 31, 2015, the Company had $2.3 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 two years.

Stock Options

Stock options generally vest equally over a three-year period, must be exercised within 10 years of the grant date and may be granted only to employees, directors and consultants. 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.

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 2014 and 2013:

	Years Ended December 31,	
	2014	2013
Dividend yield	—%	—%
Expected volatility	79.4% - 80.0%	79.6% - 79.8%
Risk-free rate	1.81% - 2.015%	0.9% - 1.815%
Expected term	6 years	6 years
Forfeiture rate	5.0%	5.0%
Stock options granted (1)	69,434	395,642
Wgtd. avg. grant date fair value per share	$2.84	$2.91
Fair value of grants (1)	$197,000	$1,150,000

(1) Prior to applying estimated forfeiture rate

The following table details stock option activity during the year ended December 31, 2015:

	Number of Options	Wgtd. Avg. Exercise Price	Wgtd. Avg. Remaining Life	Aggregate Intrinsic Value (000's)
Outstanding at beginning of year	1,517,704	$ 6.05		
Granted	—	—		
Expired/cancelled/forfeited	(155,680)	5.70		
Exercised	—	—		
Outstanding at end of year	1,362,024	6.09	5.6 years	$ —
Options exercisable at end of year	1,217,486	$ 6.33	4.4 years	$ —
Options expected to vest	137,311	4.13	7.9 years	$ —

The total fair value of stock options that vested during the years ended December 31, 2015, 2014 and 2013 was $0.8 million, $1.0 million and $0.8 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, 2015:

Range of Exercise Price	Options Outstanding 12/31/2015	Wgtd. Avg. Remaining Contractual Life	Wgtd. Avg. Exercise Price	Options Exercisable 12/31/2015	Wgtd. Avg. Exercise Price
$2.24—$4.48	386,908	7.8 years	$4.13	251,701	$4.16
$4.49—$6.72	220,487	5.7 years	$5.46	211,156	$5.48
$6.73—$8.96	744,629	4.5 years	$7.25	744,629	$7.25
$8.97—$11.20	10,000	0.1 years	$9.99	10,000	$9.99
	1,362,024	5.6 years	$6.09	1,217,486	$6.33

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 prior to 2011 generally vests over a five-year period with one-fourth vesting on each of the first, second, third and fifth anniversaries of the date of the grant. No portion of the restricted stock vests on the fourth anniversary of the date of the grant. Beginning in 2011, restricted stock granted to employees generally vests evenly over a three year period. Prior to 2013, restricted stock granted to directors generally vested evenly over a three-year period. Beginning in 2013, restricted stock granted to directors vests one year 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.

The following table details restricted stock activity during the year ended December 31, 2015:

	Number of Shares	Wgtd. Avg. Fair Value per Share
Outstanding at beginning of year	2,428,202	$ 4.37
Granted	54,717	1.27
Cancelled/forfeited	(187,730)	3.88
Lapse of restrictions	(1,110,013)	4.27
Outstanding at December 31, 2015	1,185,176	$ 3.81

The weighted average grant date fair value of restricted stock granted during the years ended December 31, 2015, 2014 and 2013 was $1.27, $4.32 and $4.18, respectively, per share. The total fair value of restricted stock that vested during the years ended December 31, 2015, 2014 and 2013 was $4.7 million, $5.0 million and $5.4 million, respectively. At December 31, 2015, the weighted average remaining life of restricted stock outstanding was approximately three years and the intrinsic value of restricted stock outstanding, using the closing stock price on December 31, 2015, was $0.6 million.

Share-Based Compensation settled in cash

Restricted Stock Units

The Company grants 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 2015, the Company paid $0.7 million for 0.7 million units that vested during the period.

Market Based Restricted Stock Units

The Company granted 243,067 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, 2015, the Company had a liability for RSUs and MRSUs outstanding in the amount of $0.2 million based upon the closing stock price at December 31, 2015.

The following table details MRSU and RSU activity during the year ended December 31, 2015:

	MRSU	RSU	Total
Outstanding at beginning of year	243,067	1,379,261	1,622,328
Granted	—	182,505	182,505
Expired/Cancelled/Forfeited	(139,784)	(120,438)	(260,222)
Vested/Paid	—	(687,704)	(687,704)
Outstanding at December 31, 2015	103,283	753,624	856,907

Note 7—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,	
	2015	2014
Asset retirement obligation, beginning of period	$ 54,970	$ 48,536
Liabilities incurred	466	756
Liabilities settled	(5,002)	(3,623)
Accretion expense	3,259	2,958
Revisions in estimated cash flows	(11,137)	6,343
Asset retirement obligation, end of period	42,556	54,970
Less: current portion of asset retirement obligation	(6,015)	(2,756)
Long-term asset retirement obligation	$ 36,541	$ 52,214

Liabilities settled during 2015 included $1.8 million as a result of the sale of our Woodford and Mississippian Lime assets.

Note 8—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, 2015 and 2014, 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 $15,940,000, ($4,237,000) and $1,098,000, Ngl hedges of $530,000, $296,000 and $61,000, and oil hedges of $644,000, $897,000 and ($232,000), for the years ended December 31, 2015, 2014 and 2013, respectively.

As of December 31, 2015, the Company had entered into the following gas hedge contract:

Production Period	Instrument Type	Daily Volumes	Weighted Average Price
Natural Gas:			
January 2016 - June 2016	Swap	10,000 Mmbtu	$3.22

At December 31, 2015, the Company had recognized an asset of approximately $1.5 million related to the estimated fair value of this derivative contract. Based on estimated future commodity prices as of December 31, 2015, the Company would realize a $0.9 million gain, net of taxes, during the next 12 months. This gain is expected to be reclassified to oil and gas sales based on the schedule of volumes stipulated in the derivative contracts.

During January 2016, the Company entered into the following additional derivative contract accounted for as a cash flow hedge:

Production Period	Instrument Type	Daily Volumes	Weighted Average Price
Natural Gas:			
July 2016 - December 2016	Swap	5,000 Mmbtu	$2.50

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, 2015 and December 31, 2014:

	Commodity Derivatives	
Period	Balance Sheet Location	Fair Value
December 31, 2015	Derivative asset	$ 1,508
December 31, 2014	Derivative asset	$ 8,631

Effect of Cash Flow Hedges on the Consolidated Statement of Operations for years ended December 31, 2015, 2014 and 2013:

Instrument	Amount of Gain (Loss) Recognized in Other Comprehensive Income	Location of Gain Reclassified into Income	Amount of Gain (Loss) Reclassified into Income
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)
Commodity Derivatives at December 31, 2013	$ (999)	Oil and gas sales	$ 927

Derivatives not designated as hedging instruments:

The Company's three-way collar contract for 2013 gas production was not designated as an effective cash flow hedge and therefore the gain on this contract was recorded as derivative income in the statement of operations. The following table reflects the effect of this contract in the consolidated statements of operations (in thousands):

Effect of Non-designated Derivative Instrument on the Consolidated Statement of Operations for the year ended December 31, 2013:

Instrument	Amount of Gain Recognized in Derivative Income
Commodity Derivatives at December 31, 2013	$ 233

Note 9 - 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, 2015 and 2014 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.

The following table summarizes the Company's assets (liabilities) that are subject to fair value measurement on a recurring basis as of December 31, 2015 and December 31, 2014 (in thousands):

	Fair Value Measurements Using		
Instrument	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Commodity Derivatives:			
At December 31, 2015	$ —	$ 1,508	$ —
At December 31, 2014	$ —	$ 8,631	$ —

The fair value of the Company's cash and cash equivalents and variable-rate bank debt approximated book value at December 31, 2015 and 2014. The fair value of the Company's $350 million of 10% Senior Notes due 2017 (the "Notes") was approximately $238 million and $301 million as of December 31, 2015 and 2014, respectively. The fair value of the Notes was determined based upon a market quote provided by an independent broker, which represents a Level 2 input.

Note 10—Long-Term Debt

On August 19, 2010, the Company issued $150 million in principal amount of the Notes and on July 3, 2013, the Company issued an additional $200 million in principal amount of its 10% Senior Notes due 2017 (collectively, the "Notes"). The Notes are guaranteed by certain of PetroQuest's subsidiaries. The subsidiary guarantors are 100% owned by PetroQuest and all guarantees are full and unconditional and joint and several. PetroQuest has no independent assets or operations and the subsidiaries not providing guarantees are minor, as defined by the rules of the Securities and Exchange Commission.

Interest is payable semi-annually on March 1 and September 1. At December 31, 2015, $11.7 million had been accrued in connection with the March 1, 2016 interest payment (which amount was reduced to $4.5 million as a result of the Exchange Offering) and the Company was in compliance with all of the covenants contained in the Notes.

The Company and PetroQuest Energy, L.L.C. (the "Borrower") have a Credit Agreement (as amended, the "Credit Agreement") with JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A., Capital One, N.A., IberiaBank, Bank of America, N.A. and The Bank of Nova Scotia. The Credit Agreement provides the Company with a $300 million revolving credit facility that permits borrowings based on the commitments of the lenders and the available borrowing base as determined in accordance with the Credit Agreement. The Credit Agreement also allows the Company to use up to $25 million of the borrowing base for letters of credit. The credit facility matures on the earlier of June 4, 2020 or February 19, 2017 if any portion of the Company's 10% Senior Notes due 2017 remains outstanding as of such date that has not been refinanced with either permitted refinancing debt or permitted second lien debt with a maturity date no earlier than 180 days after June 4, 2020, all as defined in the Credit Agreement. As of December 31, 2015 the Company had no borrowings outstanding under (and no letters of credit issued pursuant to) the Credit Agreement.

The borrowing base under the Credit Agreement is determined by March 31 and September 30 of each year and based upon the valuation of the reserves attributable to the Company's oil and gas properties as of January 1 and July 1 of each year. As of December 31, 2015, the borrowing base was $55 million (subject to the aggregate commitments of the lenders then in effect and the Company's compliance with the financial covenants thereunder). During January 2016, the borrowing base and the aggregate commitments of the lenders were reduced to $42 million. Based on the Company's expectations for the first quarter of 2016, the Company anticipates that, pursuant to the applicable financial covenants, the Company's utilization of the borrowing base will be limited to 25% of the aggregate commitments of the lenders, or $10.5 million. The next scheduled borrowing base redetermination is scheduled to occur by March 31, 2016 with additional interim redeterminations to occur on July 31 and December 31 of each year commencing on July 31, 2016. The Company or the lenders may request two additional borrowing base re-determinations each year. Each time the borrowing base is to be re-determined, the administrative agent under the Credit Agreement will propose a new borrowing base as it deems appropriate in its sole discretion, which must be approved by all lenders if the borrowing base is to be increased, or by lenders holding two-thirds of the amounts outstanding under the Credit Agreement if the borrowing base remains the same or is reduced.

The Credit Agreement is secured by a first priority lien on substantially all of the assets of the Company and its subsidiaries, including a lien on all equipment and at least 90% of the aggregate total value of the Borrower's oil and gas properties. Outstanding balances under the Credit Agreement bear interest at the alternate base rate ("ABR") plus a margin (based on a sliding scale of 1.0% to 2.0% depending on total commitments) or the adjusted LIBO rate ("Eurodollar") plus a margin (based on a sliding scale of 2.0% to 3.0% depending on total commitments). The alternate base rate is equal to the highest of (i) the JPMorgan Chase prime rate, (ii) the Federal Funds Effective Rate plus 0.5% or (iii) the adjusted LIBO rate (subject to a floor of 0.0%) plus 1%. For the purposes of the definition of alternate base rate only, the adjusted LIBO rate for any day is based on the LIBO Rate at approximately 11:00 a.m. London time on such day. For all other purposes, the adjusted LIBO rate is equal to the rate at which Eurodollar deposits in the London interbank market for one, two, three or six months (as selected by the Company) are quoted, as adjusted for statutory reserve requirements for Eurocurrency liabilities. Outstanding letters of credit are charged a participation fee at a per annum rate equal to the margin applicable to Eurodollar loans, a fronting fee and customary administrative fees. In addition, the Company pays commitment fees based on a sliding scale of 0.375% to 0.5% depending on total commitments.

The Company and its subsidiaries are subject to certain restrictive financial covenants under the Credit Agreement, including (i) a maximum ratio of total debt to EBITDAX, determined on a rolling four quarter basis, of (a) if the Company has unused availability greater than or equal to 75% of the aggregate commitments of the Lenders at all times during the consecutive three month period prior to and including the date of each fiscal quarter end, the maximum ratio of total debt to EBITDAX is 5.0 to 1.0 as of the last day of the fiscal quarter ending March 31, 2016, 5.5 to 1.0 as of the last day of the fiscal quarter ending June 30, 2016 and 5.75 to 1.0 as of the last day of the fiscal quarters ending September 30, 2016 and December 31, 2016, with in each case the amount of total debt for such quarterly period reduced by the amount of unencumbered and unrestricted cash of the Company and cash subject to an account control agreement, (b) if the Company has unused availability of less than 75% of the aggregate commitments of the Lenders at any time during the consecutive three month period prior to and including the date of calculating the ratio, the maximum ratio of total debt to EBITDAX will be 5.75 to 1.00 as of the last day of the fiscal quarters ending March 31, 2016, June 30, 2016 and September 30, 2016 and 5.25 to 1.00 as of the last day of the fiscal quarter ending December 31, 2016, and (c) 5.00 to 1.00 as of the last day of any fiscal quarter ending on or after March 31, 2017 and (ii) a minimum ratio of EBITDAX to total cash interest expense of 1.0 to 1.0, all as defined in the Credit Agreement.

In addition, the Credit Agreement permits a sale of the majority of the Company's remaining oil and gas assets in Oklahoma, provided that such sale is consummated on or prior to March 31, 2016, all of the consideration received in such sale is cash, and the borrowing base will be reduced by $10 million upon the consummation of such sale. The Credit Agreement currently prohibits the Company from declaring and paying dividends on its Series B Preferred Stock.

The Credit 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, 2015, the Company was in compliance with all such covenants contained in the Credit Agreement.

Note 11—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 2015, 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 $(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. During 2013, 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 $92,000 and $269,000, respectively, and with respect to Mr. Nordberg, costs billed exceeded revenues disbursed in the amount of $200. 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, 2015, the Company's joint interest billing receivable included approximately $10,000 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, 2015.

Periodically, the Company charters private aircraft for business purposes. During 2014, the Company paid approximately $18,200 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 2015 and 2013. 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 12—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, 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 $2.42 per Mcf of natural gas, $50.29 per barrel of oil and $2.21 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 $266.6 million during 2015. No such write-down occurred during 2014 or 2013. The Company's cash flow hedges in place at December 31, 2015 decreased the ceiling test write-down by approximately $1.1 million.

Note 13—Other Comprehensive Income

The following table represents the changes in accumulated other comprehensive income (loss), net of tax, for the year ended December 31, 2014 (in thousands):

	Gains and Losses on Cash Flow Hedges	Change in Valuation Allowance	Total
Balance as of December 31, 2013	$ (688)	$ (408)	$ (1,096)
Other comprehensive income before reclassifications:			
Change in fair value of derivatives	6,683		6,683
Income tax effect	(2,487)	408	(2,079)
Net of tax	4,196	408	4,604
Amounts reclassified from accumulated other comprehensive income:			
Oil and gas sales	3,044		3,044
Income tax effect	(1,132)	—	(1,132)
Net of tax	1,912	—	1,912
Net other comprehensive income	6,108	408	6,516
Balance as of December 31, 2014	$ 5,420	$ —	$ 5,420

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

Note 14—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 cumulative three-year 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 $143.5 million as of December 31, 2015.

An analysis of the Company's deferred taxes follows (amounts in thousands):

	December 31,		
	2015	2014	2013
Net operating loss carryforwards	$ 24,014	$ 17,705	$ 21,810
Percentage depletion carryforward	10,592	10,206	8,645
Alternative minimum tax credits	784	784	784
Contributions carryforward and other	266	241	189
Temporary differences:			
Oil and gas properties	90,291	(15,439)	(7,248)
Asset retirement obligation	15,831	20,449	18,056
Derivatives	(561)	(3,211)	408
Share-based compensation	2,291	2,560	2,887
Valuation allowance	(143,508)	(33,295)	(45,531)
Deferred taxes	$ —	$ —	$ —

At December 31, 2015, the Company had approximately $77.1 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 $8.7 million of such carryforwards would expire in 2025 and the remainder would expire by the year 2034. The Company has available for tax reporting purposes $30.3 million in statutory depletion deductions that may be carried forward indefinitely.

Income tax expense (benefit) for each of the years ended December 31, 2015, 2014 and 2013 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,		
	2015	2014	2013
Amount computed using the statutory rate	$ (102,257)	$ 9,887	$ 5,041
Increase (reduction) in taxes resulting from:			
State & local taxes	(6,477)	904	317
Percentage depletion carryforward	(404)	(1,564)	(1,323)
Non-deductible stock option expense (1)	90	213	115
Share-based compensation (2)	1,317	90	780
Other	113	(643)	1,132
Change in valuation allowance	110,244	(11,828)	(5,742)
Income tax expense (benefit)	$ 2,626	$ (2,941)	$ 320

(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 15—Commitments and Contingencies

The Company is a party to ongoing litigation in the normal course of business. While the outcome of lawsuits or other proceedings against the Company cannot be predicted with certainty, management believes that the effect on its financial condition, results of operations and cash flows, if any, will not be material.

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, 2015 under these operating leases are as follows (in thousands):

2016	$	1,419
2017		1,310
2018		452
2019		422
2020		417
Thereafter		1,225
	$	5,245

Total rent expense under operating leases was approximately $1.7 million, $1.6 million and $1.4 million in 2015, 2014 and 2013, respectively.

Note 16—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,		
	2015	2014	2013
Acquisition costs:			
Proved (1)	$ 2,287	$ 3,064	$ 177,880
Unproved (1)	2,550	39,164	35,008
Exploration costs:			
Proved	29,322	67,297	34,344
Unproved	7,677	13,515	20,112
Development costs	9,888	55,722	41,328
Capitalized general and administrative and interest costs	12,881	22,121	19,911
Total costs incurred	$ 64,605	$ 200,883	$ 328,583

	For the Year-Ended December 31,		
	2015	2014	2013
Accumulated depreciation, depletion and amortization (DD&A)			
Balance, beginning of year	$ (1,648,060)	$ (1,553,044)	$ (1,472,244)
Provision for DD&A	(62,138)	(86,406)	(69,357)
Ceiling test writedown	(266,562)	—	—
Sale of proved properties and other (2) (3)	819,305	(8,610)	(11,443)
Balance, end of year	$ (1,157,455)	$ (1,648,060)	$ (1,553,044)
DD&A per Mcfe	$ 1.82	$ 1.99	$ 1.82

(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. During 2013, the Company closed on the Gulf of Mexico Acquisition for an aggregate cash purchase price of $188.8 million (see Note 2). Additionally, the Company acquired 13,500 net unevaluated acres in Oklahoma targeting the Woodford Shale in 2013.

(2) During 2015, the Company sold its Woodford and Mississippian Lime assets for an aggregate cash purchase price of $274.1 million (see Note 2).

(3) 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. During 2013, the Company sold 50% of its saltwater disposal systems and related surface assets in the Woodford for net proceeds of approximately $10.4 million and its non-operated Wyoming assets for a cash purchase price of $1.0 million.

At December 31, 2015 and 2014, unevaluated oil and gas properties totaled $12.5 million and $109.1 million, respectively, and were not subject to depletion. Unevaluated costs at December 31, 2015 included $0.2 million of costs related to two exploratory wells in progress at year-end. These costs are expected to be transferred to evaluated oil and gas properties during 2016 upon the completion of drilling. At December 31, 2014, unevaluated costs included $16.8 million related to 16 exploratory wells in progress. All of these costs were transferred to evaluated oil and gas properties during 2015. The Company capitalized $4.7 million, $10.0 million and $6.6 million of interest during 2015, 2014 and 2013, respectively. Of the total unevaluated oil and gas property costs of $12.5 million at December 31, 2015, $(3.1) million, or (25)%, was incurred in 2015, $3.6 million, or 29%, was incurred in 2014 and $12.1 million, or 96%, was incurred in prior years. The Company expects that the majority of the unevaluated costs at

December 31, 2015 will be evaluated within the next 3 years, including $0.2 million that the Company expects to be evaluated during 2016.

Oil and Gas Reserve Information

The Company's net proved oil and gas reserves at December 31, 2015 have been estimated by independent petroleum engineers in accordance with guidelines established by the SEC using a historical 12-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.

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, 2012	1,635	24,366	188,264	222,441
Revisions of previous estimates	(156)	804	38,383	38,247
Extensions, discoveries and other additions	434	6,099	30,429	39,132
Purchase of producing properties	1,833	1,915	22,274	35,187
Sale of reserves in place	(34)	—	(15)	(218)
Production	(681)	(4,754)	(29,226)	(38,066)
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
Proved developed reserves				
As of December 31, 2013	2,709	23,173	163,728	203,152
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
Proved undeveloped reserves				
As of December 31, 2013	322	5,257	86,381	93,571
As of December 31, 2014	348	30,914	126,458	159,460
As of December 31, 2015	257	19,034	53,811	74,389

Year Ended December 31, 2015

During 2015, the Company's estimated proved reserves decreased by 55%. Sales of reserves in place was primarily due to the divestiture of the majority of the Company's Woodford 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.

Year Ended December 31, 2013

Extensions, discoveries and other additions were primarily due to the success of the Company's Oklahoma, Texas and Gulf Coast drilling programs. The Company added approximately 23 Bcfe of proved reserves in Oklahoma, 5 Bcfe in the Gulf Coast and 10 Bcfe in Texas. Revisions of previous estimates were primarily a result of the increase in the historical 12-month average price per Mcf of natural gas used to calculate estimated proved reserves, which was $3.11 per Mcf at December 31, 2013 as compared to $2.20 per Mcf at December 31, 2012. The 35 Bcfe added through purchase of producing properties relates to the Company's Gulf of Mexico Acquisition (See Note 2).

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,		
	2015	2014	2013
Future cash flows	$ 487,834	$ 1,711,404	$ 1,243,627
Future production costs	(171,678)	(372,690)	(295,666)
Future development costs	(116,591)	(244,784)	(185,188)
Future income taxes	—	(121,192)	(37,404)
Future net cash flows	199,565	972,738	725,369
10% annual discount	(71,880)	(424,176)	(274,189)
Standardized measure of discounted future net cash flows	$ 127,685	$ 548,562	$ 451,180

Changes in Standardized Measure

	Year Ended December 31,		
	2015	2014	2013
Standardized measure at beginning of year	$ 548,562	$ 451,180	$ 230,823
Sales and transfers of oil and gas produced, net of production costs	(55,849)	(173,540)	(134,184)
Changes in price, net of future production costs	(267,710)	37,204	55,601
Extensions and discoveries, net of future production and development costs	70,928	237,290	70,181
Changes in estimated future development costs, net of development costs incurred during this period	31,007	11,094	(25,389)
Revisions of quantity estimates	(14,427)	25,591	58,508
Accretion of discount	60,071	47,130	23,776
Net change in income taxes	52,149	(32,034)	(13,182)
Purchase of reserves in place	—	—	191,964
Sale of reserves in place	(194,454)	(7,240)	(411)
Changes in production rates (timing) and other	(102,592)	(48,113)	(6,507)
Net increase (decrease) in standardized measure	(420,877)	97,382	220,357
Standardized measure at end of year	$ 127,685	$ 548,562	$ 451,180

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

	2015	2014	2013
Oil, $/Bbl	$50.29	$96.45	$106.19
Ngls, $/Mcfe	2.24	4.11	5.10
Natural Gas, $/Mcf	2.41	3.80	3.11

Note 17 - 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**
2015:				
Revenues	$ 33,451	$ 32,550	$ 26,872	$ 23,096
Loss from operations (1)	(121,887)	(57,796)	(50,617)	(61,864)
Loss available to common stockholders (1)	(122,240)	(61,083)	(51,910)	(64,696)
Earnings per share:				
Basic	$ (1.89)	$ (0.94)	$ (0.80)	$ (0.98)
Diluted	$ (1.89)	$ (0.94)	$ (0.80)	$ (0.98)
2014:				
Revenues	$ 59,966	$ 60,581	$ 56,486	$ 47,988
Income from operations	11,323	10,879	5,569	478
Income available to common stockholders	10,043	9,592	4,671	1,745
Earnings per share:				
Basic	$ 0.15	$ 0.15	$ 0.07	$ 0.02
Diluted	$ 0.15	$ 0.15	$ 0.07	$ 0.02

(1) Loss from operations and net 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 net 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.

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CORPORATE INFORMATION

BOARD OF DIRECTORS

Charles T. Goodson
Chairman of the Board,
Chief Executive Officer, and President

W.J. Gordon III *#^
President, CEO, and Founder of TGA Global Consulting Group

Michael L. Finch *#^
Private Investments

Charles F. Mitchell II, M.D. *#^
Physician, Private Investments

E. Wayne Nordberg *#^
Hollow Brook Associates, LLC

William W. Rucks, IV *#^
Private Investments

* 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

Tracy Price
Executive Vice President
Business Development & Land

Edward E. Abels, Jr.
Executive Vice President, General Counsel,
and Corporate Secretary

Stephen H. Green
Senior Vice President
Exploration

Mark K. Castell
Vice President - Oklahoma Assets

Edgar A. Anderson
Vice President - ArkLaTex

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LEGAL COUNSEL

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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 18, 2016, 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.

COMMON STOCK LISTING

Listed on NYSE as PQ

PetroQuest Energy, Inc.

WWW.PETROQUEST.COM

NYSE:PQ