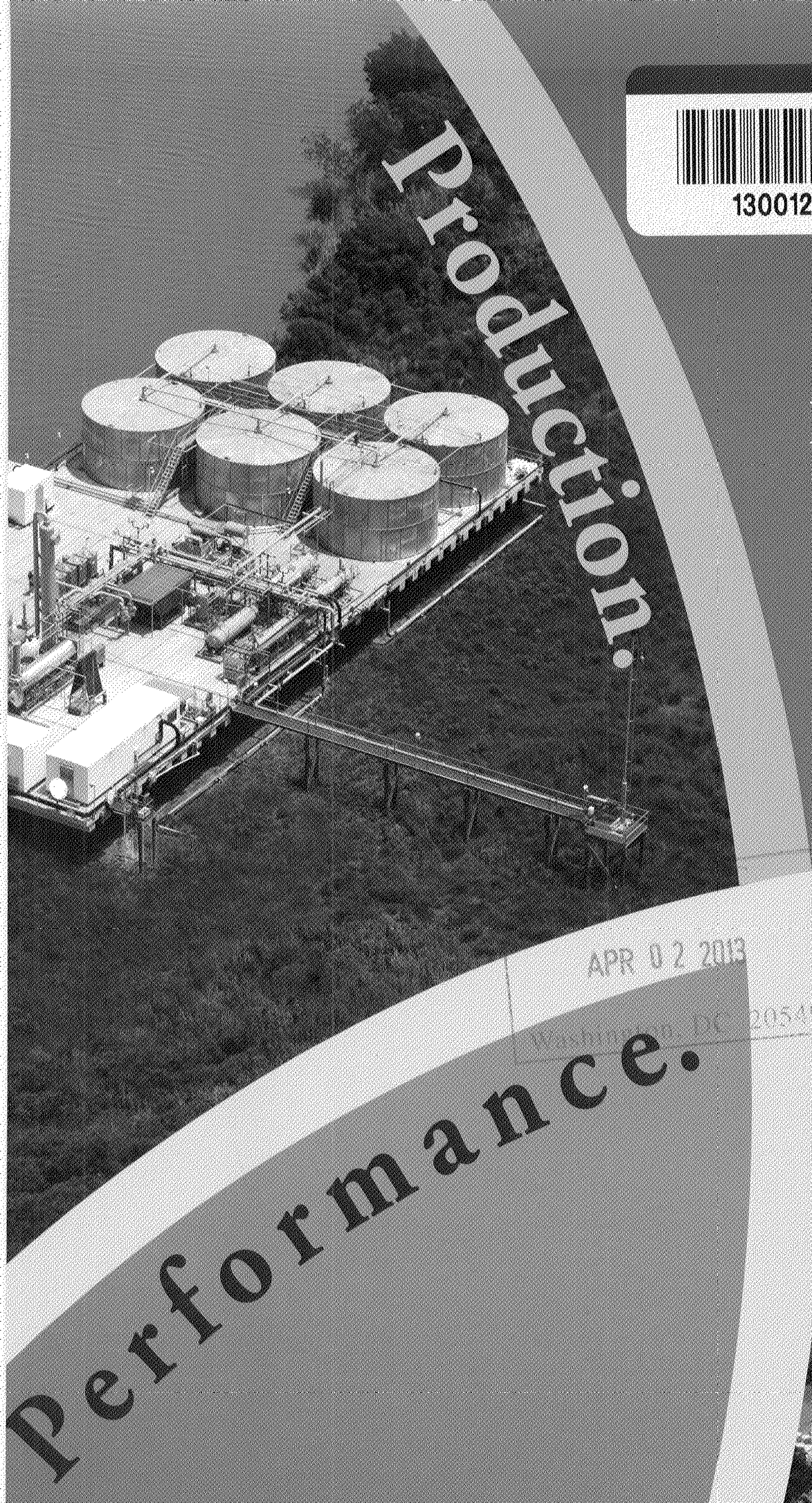


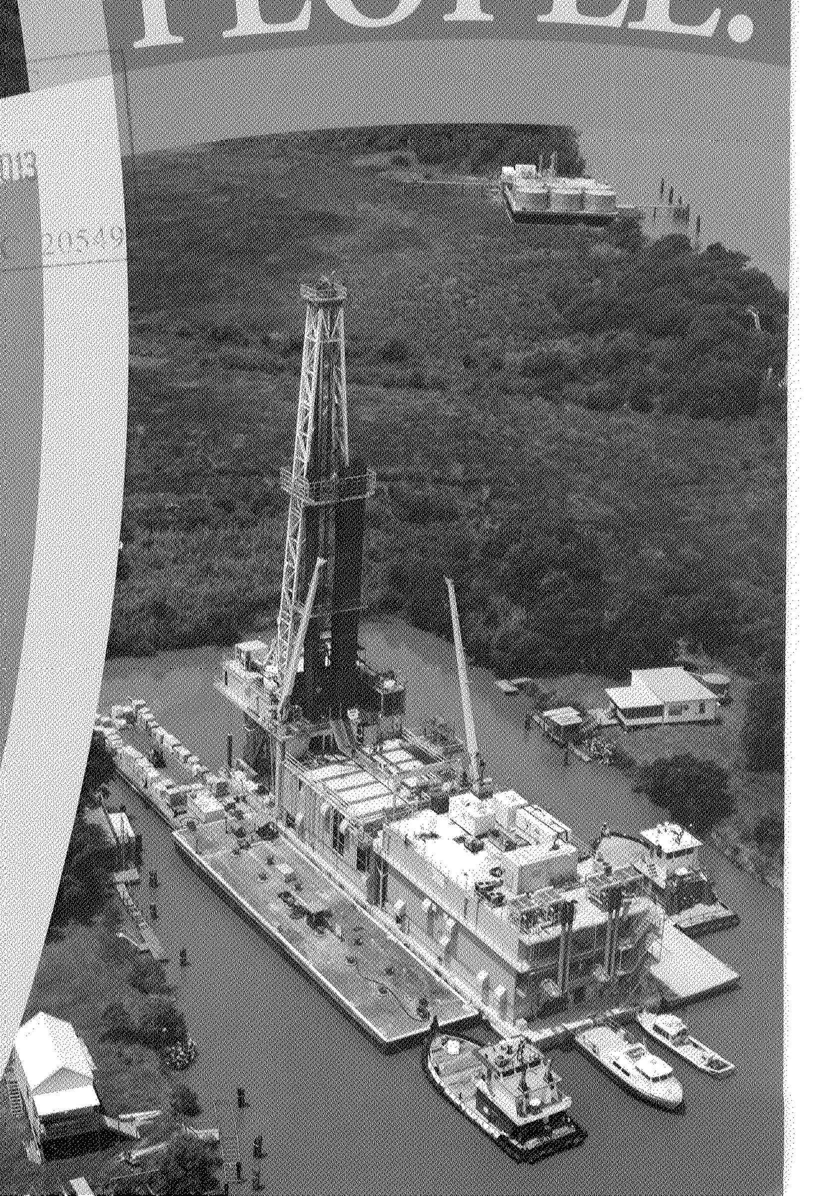
PetroQuest Energy, Inc.

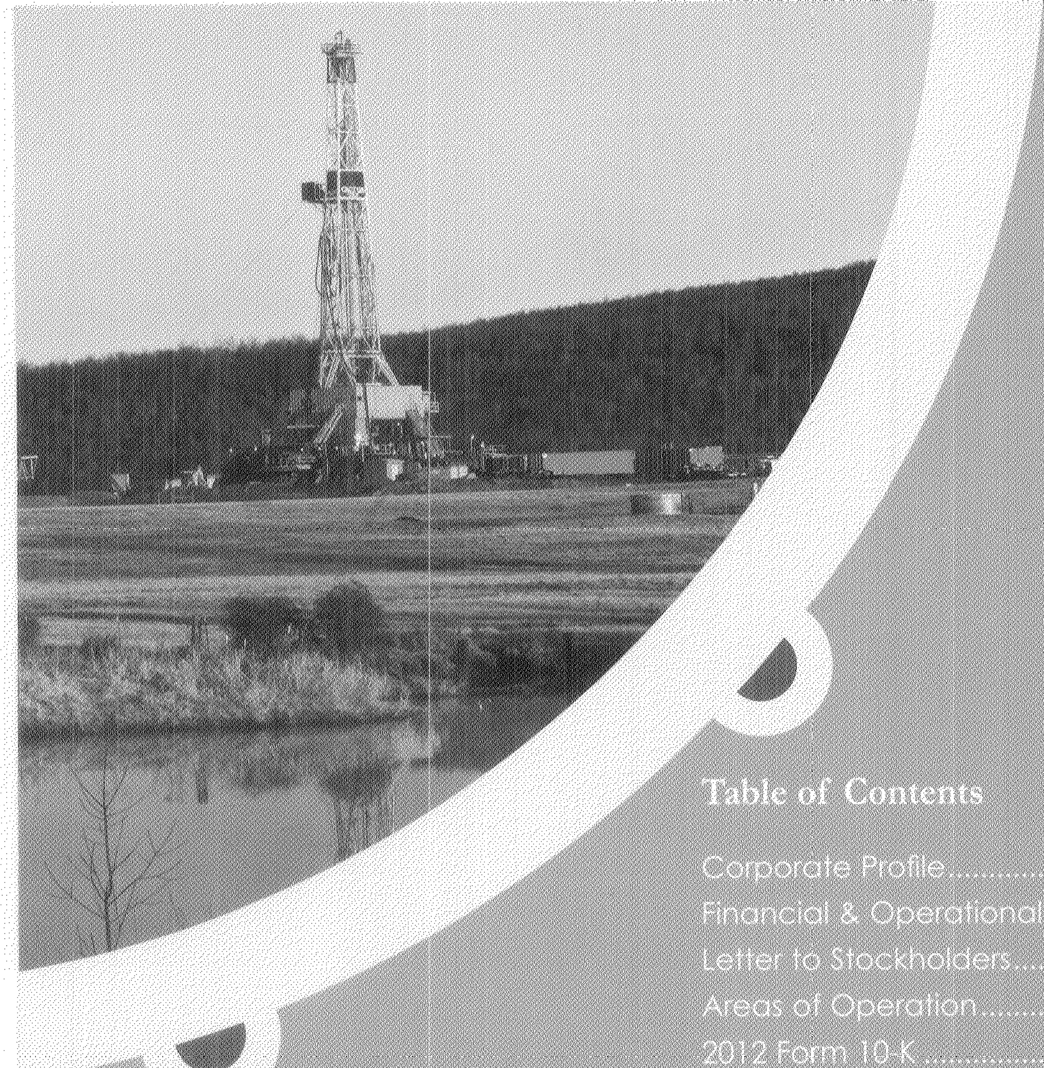
2012 ANNUAL REPORT

Production.

PEOPLE.

Performance.





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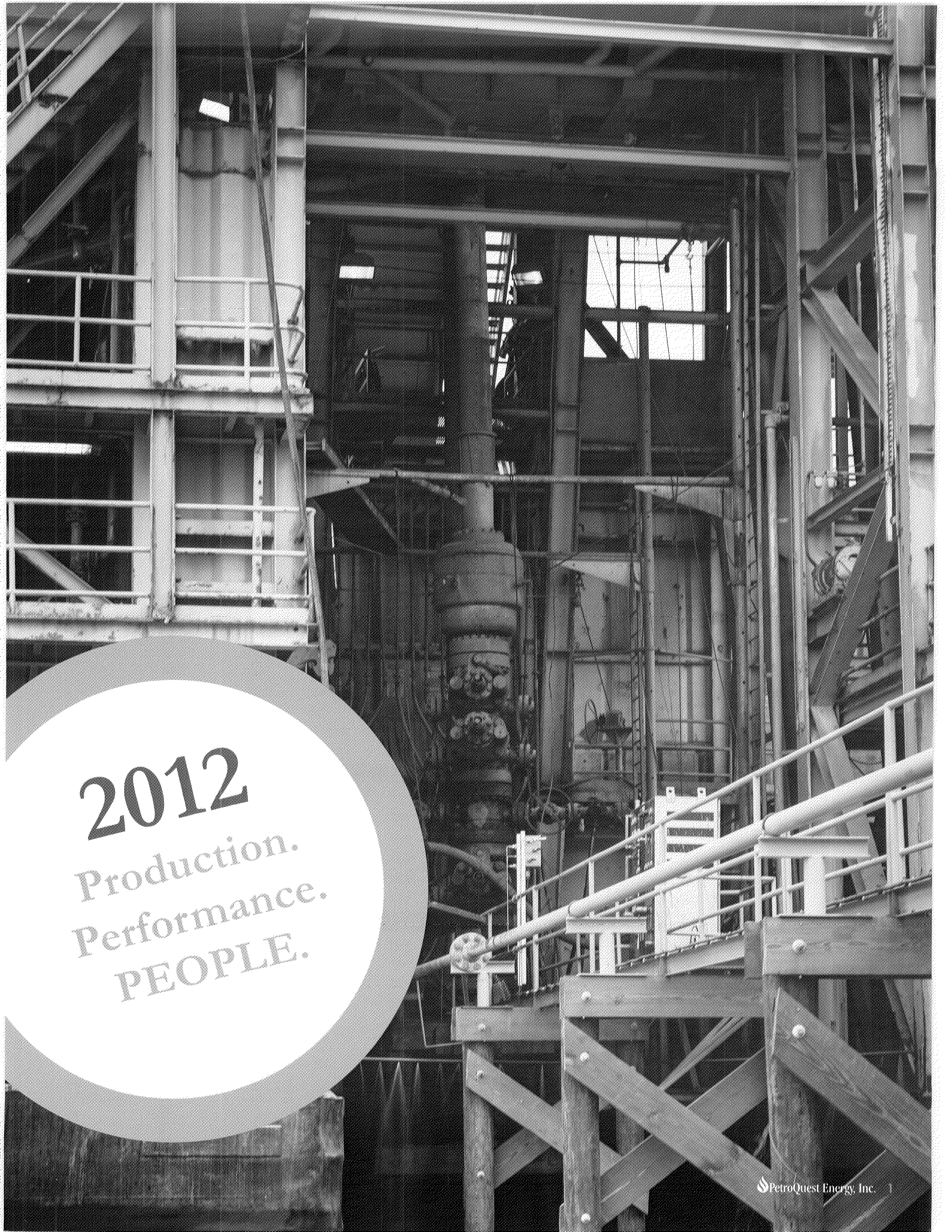
Corporate Profile

PetroQuest Energy, Inc. is an independent energy company engaged in the exploration, development, acquisition and production of oil and natural gas reserves in Texas, the Arkoma Basin, South Louisiana and the shallow waters of the Gulf of Mexico.

Cover Photos - La Cantera production facilities and Broussard Estates #2 well at the La Cantera Field, Vermilion Parish, LA


2012
Production.
Performance.
PEOPLE.

Financial & Operational Highlights

	2007 Annual	2008 Annual	2009 Annual	2010 Annual	2011 Annual	2012 Q1	2012 Q2	2012 Q3	2012 Q4	2012 Annual
Production										
Natural Gas, MMcf	22,650	27,032	28,065	24,502	24,463	6,729	6,945	6,889	6,903	27,466
NGL, MMcfe	2,316	2,676	2,533	2,470	2,288	593	763	894	1,116	3,367
Crude Oil, MBbl	1,080	681	600	663	572	141	116	123	141	521
Natural Gas, MMcfe	31,444	33,792	34,199	30,951	30,183	8,170	8,405	8,519	8,863	33,957
Financial ($ Thousands, except per share amounts)										
Total Revenues	$ 262,334	$ 313,958	$ 218,684	$ 179,263	$ 160,700	$ 36,041	$ 33,413	$ 33,951	$ 38,186	$ 141,591
Net Income (Loss)	40,619	(96,960)	(90,190)	47,126	10,548	(17,326)	(53,232)	(37,354)	(24,167)	(132,079)
Preferred Stock Dividends	1,374	5,140	5,140	5,139	5,139	1,282	1,288	1,285	1,284	5,139
Net Income (Loss) Available to Common Stockholders	$ 39,245	$ (102,100)	$ (95,330)	$ 41,987	$ 5,409	$ (18,608)	$ (54,520)	$ (38,639)	$ (25,451)	$ (137,218)
Per Common Share: Basic	$ 0.79	$ (2.08)	$ (1.72)	$ 0.67	$ 0.08	$ (0.30)	$ (0.87)	$ (0.62)	$ (0.41)	$ (2.20)
Diluted	$ 0.78	$ (2.08)	$ (1.72)	$ 0.66	$ 0.08	$ (0.30)	$ (0.87)	$ (0.62)	$ (0.41)	$ (2.20)

Year-Over-Year Review

	2007	2008	2009	2010	2011	2012
Reserves ($ Thousands, except per share amounts)						
Natural Gas, MMcf	129,154	158,781	156,853	174,566	241,926	192,968
NGL, MMcfe	13,314	13,405	10,508	8,373	15,111	25,360
Crude Oil, MBbl	2,342	2,201	1,931	1,623	1,395	1,655
Natural Gas, MMcfe	156,520	185,392	178,947	192,677	265,407	228,258
Percent Developed	69 %	73 %	62 %	65 %	61 %	74 %
Future Undiscounted Net Cash Flows, $000s	$ 779,395	$ 466,449	$ 272,271	$ 442,505	$ 635,327	$ 406,818
SEC PV-10, Before Taxes, $000s	$ 540,651	$ 327,193	$ 176,995	$ 255,651	$ 341,373	$ 239,269
Commodity Prices						
PetroQuest Realized, Natural Gas, $/Mcf	$ 7.21	$ 8.00	$ 5.84	$ 4.37	$ 3.22	$ 2.31
Henry Hub Cash Market Average, Natural Gas, $/Mcf	6.97	8.89	3.94	4.37	4.00	$ 2.75
PetroQuest Realized, NGL, $/Mcfe	7.93	9.76	5.38	7.78	9.51	$ 6.32
PetroQuest Realized, Crude Oil, $/Bbl	70.52	97.49	68.57	79.47	104.99	$ 108.97
WTI (Cushing) Spot Average, Crude Oil, $/Bbl	72.23	99.92	61.99	79.51	95.04	$ 94.10
PetroQuest Realized, Natural Gas Equivalent, $/Mcfe	8.15	9.13	6.39	5.78	5.32	$ 4.17
Per Unit Analysis, $/Mcfe						
Total Revenues	$ 8.34	$ 9.29	$ 6.40	$ 5.79	$ 5.32	$ 4.17
Lease Operating Expense and Production Taxes	1.27	1.69	1.26	1.42	1.38	$ 1.17
Gas Gathering Costs	0.13	0.07	0.01	0.00	0.00	$ 0.00
Gross Operating Margin	6.94	7.53	5.13	4.37	3.94	$ 3.00
Interest Expense	0.43	0.28	0.37	0.32	0.32	$ 0.29
General and Administrative	0.67	0.69	0.55	0.69	0.68	$ 0.68
Preferred Stock Dividends	0.04	0.15	0.15	0.17	0.17	$ 0.15
Gross Cash Margin	$ 5.80	$ 6.41	$ 4.06	$ 3.19	$ 2.77	$ 1.88

"I remain as bullish as ever on PetroQuest's prospects in 2013 and beyond."

To Our Stockholders

PetroQuest Delivers Asset Diversity: The Key to Success in Challenging Commodity Price Environments

For the past several years, my position in communicating with PetroQuest stockholders has been that the U.S. gas markets should recover in parallel with an improving economy and an increase in demand associated with greater use of natural gas in the power generation and transportation sectors. I still believe that ultimately these macro forces will converge and that an investment in PetroQuest will be rewarded as we accelerate production to capture additional value for stockholders in a commodity price recovery. The question is when.

In previous annual reports, I have had the opportunity to review and discuss a broad range of economic factors impacting both the United States and Federal Reserve District 6, which comprises Alabama, Georgia, Florida, and parts of Louisiana, Tennessee and Mississippi. What has become clear to me in reviewing the broader economic data is that national and regional economic recovery has been slower than expected. Further, I thought that larger-scale conversion to natural gas as a transportation fuel would have been happening at a faster pace than what we are presently witnessing. These factors, coupled with the large gas volumes that continue to be produced, even in "liquids-rich" hydrocarbon plays, have together contributed to continued and robust gas production volumes, the result of which has been low gas prices in the U.S. As we have said for many years, the strategic imperative of diversifying our reserves, beginning in 2003, now provides us with the flexibility to pursue projects which will create the most value for our stockholders during this sustained period of low gas prices.

La Cantera Discoveries Represent Long-Term Opportunities for PetroQuest Stockholders

Given the reality of the gas markets in 2012 and into 2013, PetroQuest has to closely scrutinize the economic returns of each project in order to select the best well prospects to drill when gas prices remain low for extended periods of time. I can share the good news that PetroQuest is better-positioned than many companies because we have both a fully committed drilling joint venture partner and a portfolio of very economic projects in South Louisiana. I am referring to our La Cantera project.

Big Wells Mean Big Returns In Low Commodity Price Environments

In recent years we have prioritized our participation in a number of liquids-rich plays. However, the economics of these plays are challenging on a well-by-well basis when gas prices are consistently below $4.00, simply because liquids-rich wells do still produce meaningful volumes of dry gas. Given this reality, the Gulf Coast projects we have in our portfolio produce significant internal rates of return on a well-by-well basis,

because the high flow rates and premium pricing enable faster returns on allocated capital.
La Cantera was the single largest discovery in the history of our Company. At December 31, 2012, gross proved reserves associated with the La Cantera structure were 112 Bcfe and the project had a gross PV-10 value of approximately $250 million. To put this single project in context, the market capitalization of PetroQuest at the end of 2012 was $310 million.

Wells like La Cantera are truly the proverbial "game-changers" for this Company. Our Thunder Bayou prospect, which is located approximately two miles north of La Cantera, falls within this category. If successful, this well could materially add to PetroQuest's reserve base and production profile in 2014. It makes intuitive sense for PetroQuest to prioritize drilling these types of wells because we would have to drill numerous wells in our other resource plays to generate similar production and cash flow as a single La Cantera type project. Although we remain committed over the long-term to developing our other resource prospects, given the potential of lower gas prices over the next year, the Board and I share the view that the best interests of our stockholders are served by allocating more capital to these types of projects, which will generate large cash flows and quicker payouts, on a well-by-well basis.
Over the past ten years, our Gulf Coast projects have generated the cash flow we have redeployed for drilling in other areas, so on some level the large Gulf Coast wells like La Cantera have been our foundation for some time. Now is the right time to allocate higher capital spending in these areas to again focus on Gulf-Coast generated cash flow in 2013. This is value creation for our stockholders in a low natural gas price environment and highlights the flexibility the Company has in allocating our capital where it will produce the best returns.
We intend to allocate approximately 32% of our 2013 capital expenditures to the Gulf Coast.

Evolution of the Woodford Continues

Although the Gulf Coast is a focus area for us in 2013, our continuing commitment to our diversification strategy and our mid-continent assets is reflected in the fact we are deploying 29% and 9% of our capital program in the Woodford and Mississippian Lime plays, respectively. For our stockholders, the highlight is that the Woodford continues to evolve as a liquids-rich play, where we plan to drill 12-15 wells in 2013. We have continued to add acreage to our Woodford position, and we grew net production from here by 28% in 2012. The NGL production component from this asset grew from 0 bbl/d at the beginning of the year to over 900 bbl/d by year end. The Woodford was the original area of focus for our joint venture partnership, in which PetroQuest has a drilling carry whereby its pays 25% of the well cost for 50% ownership. The balance on the drilling carry at year end 2012 was $71 million. Our Woodford program remains excellent business for PetroQuest stockholders even in a low gas price environment where we are projecting internal rates of return north of 80% using strip pricing.

"The Woodford continues to evolve as a liquids-rich play, where we plan to drill 12-15 wells in 2013."

Mississippian Lime Is An Emerging Play

Likewise, we established initial production on eight of the wells we tested in our Mississippian Lime acreage in northern Oklahoma in 2012. We intend to release the rig in order to move into the next phase of our development, which will entail the collection and evaluation of 3D seismic data over our acreage. This data, coupled with our well results, will form the basis for us to further delineate our acreage in terms of identifying the best prospects for the next phase of drilling. Once we fully appraise the seismic data on our Mississippian Lime acreage, we will move forward with the next phase of drilling, so I believe this area remains one of our focus areas for future oil production growth.

Horizontal Cotton Valley – Preserved for Future Production Growth

Lastly, we remain active in our Cotton Valley play in East Texas. We grew production in the play by 56% last year and at year end 2012 we were producing more than 650 barrels of natural gas liquids per day with an additional well completion expected in March 2013. We will allocate 8% of our capital program for 2013 to East Texas. For the remainder of the year we will focus on production in this area, rather than drilling new wells. Our Cotton Valley acreage is held by production, which means that we are in a position to slow our activity until later in 2013, given the expectation that commodity prices will have begun some level of recovery.

Outlook for 2013

The perennial question in the oil and gas business is the magnitude and timing of commodity price changes; this has and will always be the central issue driving our capital allocation decisions. Because we do not forecast a sustained recovery in gas prices in 2013, we plan to allocate 35% less capital than in 2012. Despite a lower capital program, we will still be able to deliver modest production growth while drilling within cash flow. This is a critical point highlighting the strength of our asset portfolio. We can deliver production growth, or maintain flat production, by spending significantly below cash flow. The advantage is that we can quickly return to a more aggressive production and reserves growth profile by increasing our capital spending if and when commodity prices support such a strategy, while at the same time remaining well within our estimated cash flow for 2013. Because we operate the majority of our activity, we control our capital allocation decisions and will be able to manage our operations to balance the competing challenges of production growth and reserve replacement in a low commodity price environment.

The biggest differentiator in 2013 will be that we are allocating a larger percentage of our capital expenditure program to our Gulf Coast properties than in recent years. This is true because the drilling inventory we have represents the best opportunity in our portfolio to generate substantial risk adjusted rates of return, even at low gas prices. The Board and I remain convinced that our strategy of diversifying our reserve base is the right way to proceed for the long-term benefit of our stockholders. This means that we will also continue to evaluate non-core acreage for potential divesture as a way to focus the story and to increase liquidity. We did this by divesting our Fayetteville and a 50% interest in our Woodford SWD systems, and will likely consider selling our Eagle Ford position for the same reasons.

The combination of these factors enables me to outline our 2013 operational priorities, which I believe is the best way to position the Company for value creation over the next few years:

- We will focus on our Gulf Coast and liquids-rich Woodford projects as we prioritize rates of return;
- We will slow the pace of development in some of our other asset areas to essentially preserve our growth profile;
- We will continue to evaluate non-core assets for potential divestiture;
- We will add acreage in those areas where we believe we will have higher rate of return projects in the near term.

PetroQuest's Employees Are the Catalysts of Stockholder Value

I have explained our operational rationale for allocating more capital to the Gulf Coast in 2013. It is equally important, however, for me to point out that our dedicated geological and geophysical (G&G) teams are responsible for identifying and nurturing the prospects in this basin. These are unique projects within the E&P business, because the wells can be expensive and involve risk. For that reason they are not every company's operational "cup of tea." PetroQuest has over the years demonstrated that technically our teams are as good as anyone in the business, and our G&G, engineering and land teams have done superlative work in quietly developing our Gulf Coast projects. These employees are responsible for generating more than $300 million in free cash flow since 2007. This is an advantage we have because many of our employees have been with the Company through the ebbs and flows of the commodity price cycle dating to the very foundation of the Company in 1985.

Long-term Employee Relations Drives Our Success

Each year I make it a priority in this letter to commend our employees as a group, because they are responsible for PetroQuest's success year in and year out. As we enter our 18th year in business under the PetroQuest name, I thought I would highlight the contributions of our longest-serving employee to illustrate that we are committed to long-term success within the Company because the Board and I know this is how we will deliver long-term value for our stockholders. Every day each one of our employees goes to work in order to contribute to PetroQuest's growth. From our administrative personnel, to our landmen, technical staff, field personnel, and our executives, we are each committed to the Company for the long haul.

PetroQuest's First Employee is Still Working For Our Stockholders Today

No one better demonstrates this commitment than Pat Landry, who was the Company's first employee in 1985. Pat graduated from the University of Southwestern Louisiana with a degree in Geology, and was hired shortly after receiving his diploma. Pat has been involved in every major initiative in PetroQuest's history, ranging from the La Cantera project to the Mississippi Lime to the Eagle Ford Shale, the Woodford, and our legacy offshore shallow Gulf of Mexico projects. Pat has truly "seen it all" in terms of PetroQuest's operations throughout the Company's history. He has been a key contributor in our major acquisition and development projects over the years; Pat's insight and expertise in evaluating projects complements PetroQuest's strategic programs and has directly contributed to the flexibility we have in our project portfolio.

Our Team Produces Positive Results

Although Pat is well-known inside the Company for his long-term commitment to PetroQuest, he is by no means alone. As I've said many times, our team is in my view the best in the business and I'm proud to be associated with Pat and many others like him. PetroQuest employees have collectively produced positive results year over year for our Company during very challenging market conditions because of their tireless dedication.

Where Do We Go From Here?

I remain as bullish as ever on PetroQuest's prospects in 2013 and beyond.

I still believe that the combination of an improving economy and an increase in natural gas usage will combine to create a positive trajectory for natural gas prices. Since the end of 2012, the Henry Hub spot price for natural gas has increased 15%. Given the reduction in gas storage from last year, I am optimistic about the gas markets continuing to outperform last year's prices. I also think that the expectation of growth for the sake of growth, a sentiment that was enabled by increasing commodity prices over the past 20 years, will have to be tempered in the near term. Companies with longevity, demonstrated performance in a number of commodity cycles, and a high-quality asset portfolio will be the companies that will provide the best returns to investors over the long term. I believe PetroQuest is one of these companies, because we are managing our operations by prioritizing projects on the basis of rates of return.

We will continue to provide growth in a low-price environment by managing costs and developing new projects and new drilling inventory. This is why investors should be reminded of the confidence I have in our teams, because Pat Landry and others like him are going to work every day seeking to improve the Company's performance on behalf of stockholders, whether measured over quarters or years.

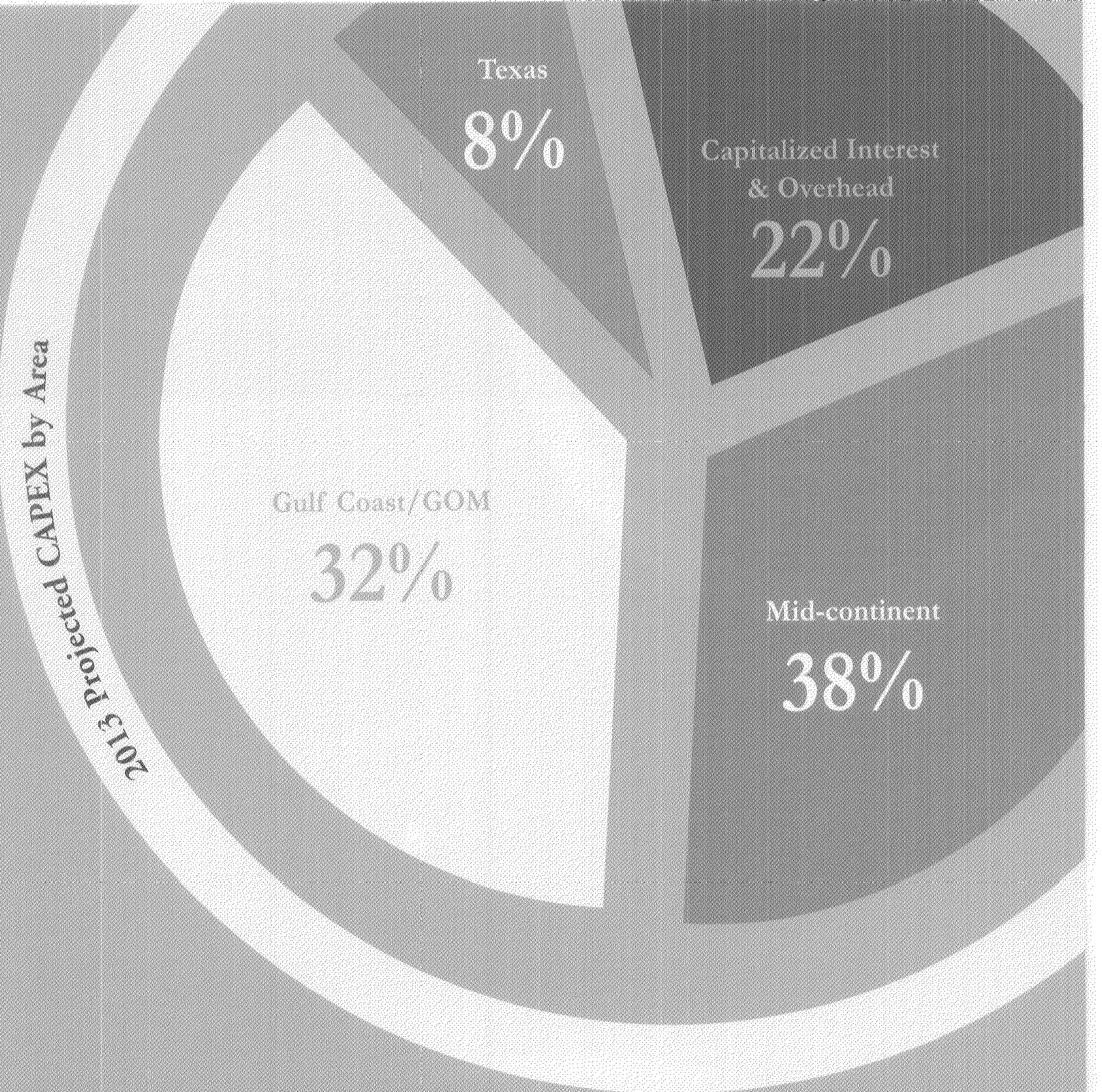
I am proud to lead the PetroQuest team and believe that our best years remain ahead.

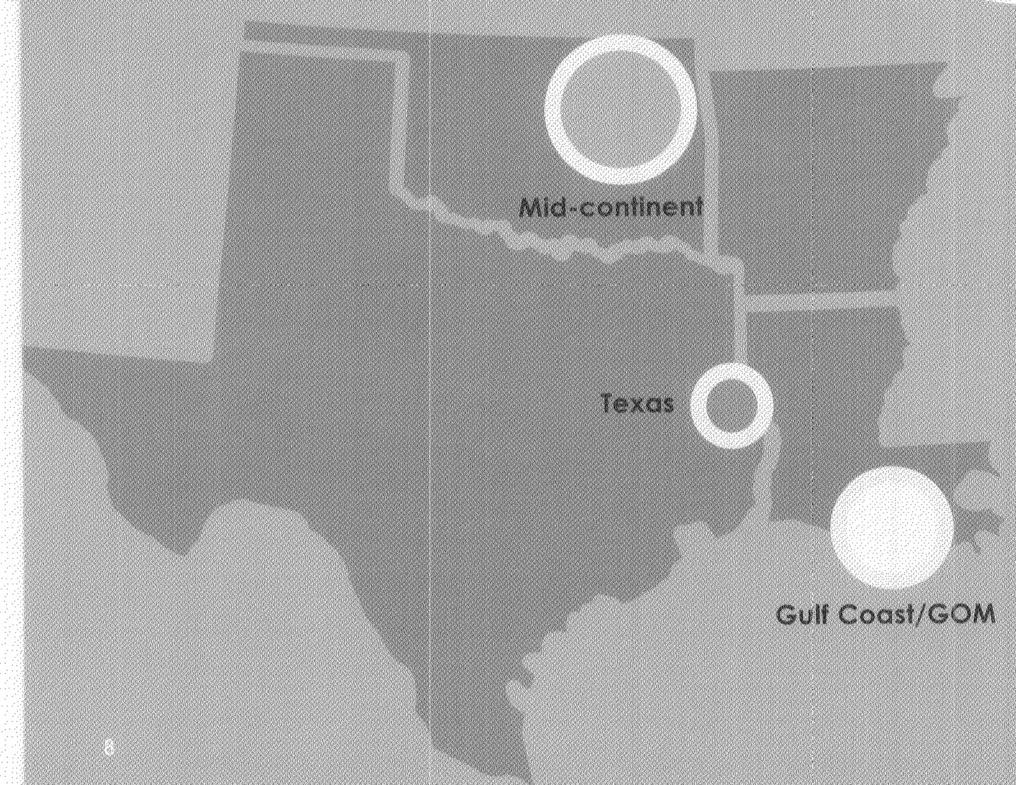
Charles T. Goodson

Charles T. Goodson
Chief Executive Officer
March 21, 2013

"Approximately 20% of the current employees have been with the Company for over 10 years."

"PetroQuest employees have collectively produced positive results year over year for our Company due to their tireless dedication."


2013 Projected CAPEX by Area
Texas
8%
Capitalized Interest
& Overhead
22%
Gulf Coast/GOM
32%
Mid-continent
38%


Mid-continent
Texas
Gulf Coast/GOM

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, 2012
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 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		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 was approximately $261,000,000 as of June 29, 2012 (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 28, 2013, the registrant had outstanding 64,570,864 shares of Common Stock, par value $.001 per share.

Document incorporated by reference: portions of the definitive Proxy Statement of PetroQuest Energy, Inc. relating to the Annual Meeting of Stockholders to be held on May 21, 2013, which are incorporated by reference into Part III of this Form 10-K.

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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 depressed natural gas prices since the middle of 2008;
- our indebtedness and the significant amount of cash required to service our indebtedness;
- the recent financial crisis and continuing uncertain economic conditions in the United States and globally;
- ceiling test write-downs resulting, and that could result in the future, from lower oil and natural gas prices;
- 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 restrictive debt covenants;
- our ability to find, develop, produce and acquire additional oil and natural gas reserves that are economically recoverable;
- approximately one quarter 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;
- 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;
- competition from larger oil and natural gas companies;
- the likelihood that our actual production, revenues and expenditures related to our reserves will differ from our estimates of proved reserves;
- our ability to identify, execute or efficiently integrate future acquisitions;
- losses or limits on potential gains resulting from hedging production;
- the loss of key management or technical personnel;
- 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; and
- potential conflicts of interest resulting from ownership of working interests and overriding royalty interests in certain of our properties by our officers and directors.

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 51.

Part I

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

Overview

PetroQuest Energy, Inc. is an independent oil and gas company incorporated in the State of Delaware with operations in Oklahoma, Texas, the Gulf Coast Basin and Wyoming. 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 in 1985 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 in Oklahoma, Wyoming and Texas through a combination of selective acquisitions and drilling activity. Beginning in 2003 with our acquisition of the Carthage Field in Texas through 2012, we have invested approximately $998 million into growing our longer life assets. During the nine year period ended December 31, 2012, we have realized a 95% drilling success rate on 878 gross wells drilled. Comparing 2012 metrics with those in 2003, the year we implemented our diversification strategy, we have grown production by 252% and estimated proved reserves by 174%. At December 31, 2012, 87% of our estimated proved reserves and 75% of our 2012 production were derived from our longer life assets.

During late 2008, in response to declining commodity prices and the global financial crisis, we shifted our focus from increasing reserves and production to building liquidity and strengthening our balance sheet. Because of our significant operational control, we were able to reduce our capital expenditures from $358 million in 2008 to $59 million in 2009 allowing us to utilize our cash flow from operations, combined with proceeds from an equity offering, to repay $130 million of bank debt. While we achieved our goal of strengthening the financial position of the Company, because of the reduced capital investments during 2009, our production declined by 9% during 2010.

Gas prices have remained weak since late-2008. As a result of the impact of low natural gas prices on our revenues and cash flow, we have focused on growing our reserves and production through a balanced drilling budget with an increased emphasis on growing our oil and natural gas liquids production. In May 2010, we entered into the Woodford joint development agreement ("JDA"), which provided us with $85 million in cash during 2010 and 2011, along with a drilling carry that we have utilized since May 2010 to enhance economic returns by reducing our share of capital expenditures in the Woodford and Mississippian Lime. As a result of the Woodford JDA and the success of our drilling programs, we have grown our estimated proved reserves by 18% and production by 10% since 2010, while maintaining our long-term debt 28% below 2008 levels.

During February 2012, we amended the JDA to accelerate the entry into Phase 2 of the drilling program effective March 1, 2012 and modify the drilling carry ratio. Under the amended JDA, the Phase 2 drilling carry was expanded to provide for development in both the Mississippian Lime and Woodford Shale plays whereby we will pay 25% of the cost to drill and complete wells and receive a 50% ownership interest. The Phase 2 drilling carry is subject to extensions in one-year intervals and as of December 31, 2012, approximately $70.7 million remained available. See "Liquidity and Capital Resources-Source of Capital: Joint Ventures".

Business Strategy

Maintain Our Financial Flexibility. Because we operate approximately 77% of our total estimated proved reserves and manage the drilling and completion activities on an additional 7% of such reserves, we expect to be able to control the timing of a substantial portion of our capital investments. Our 2013 capital expenditures, which include capitalized interest and overhead, are expected to range between $80 million and $100 million, which at the midpoint represents a 33% decrease from our capital expenditures during 2012. We expect to be able to actively manage our 2013 capital budget in the event commodity prices, or the health of the global financial markets, do not match our expectations. During 2013, we also plan to maintain our commodity hedging program and, as in during prior years, we may continue to opportunistically dispose of certain non-core or mature assets to provide capital for higher potential exploration and development properties that fit our long-term growth strategy. During December 2012, we sold our non-operated Arkansas assets for $9.2 million. During January 2013, we sold 50% of our saltwater disposal systems and related surface assets in the Woodford for net proceeds of approximately $10 million.

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. We plan to allocate our 2013 capital investments in a manner that continues to geographically and operationally diversify our asset base, while focusing on oil and natural gas liquids projects as the pricing for these products is presently expected to be more attractive than that of natural gas. Through our portfolio diversification efforts, at December 31, 2012, approximately 87% of our estimated proved reserves were located in longer life and lower risk basins in Oklahoma, Texas and Wyoming and 13% were located in the shorter life, but higher flow rate reservoirs in the Gulf Coast Basin. In terms of production diversification, during 2012, 75% of our production was derived from longer life basins versus 66% and 54% in 2011 and 2010, respectively. Our 2012 production was comprised of 81% natural gas, 9% oil and 10% 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. During 2013, we intend to primarily target properties that provide us with exposure to oil or natural gas liquids reserves and production. In evaluating these targets, 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. During 2012, we expanded our acreage positions targeting the Mississippian Lime, a primarily oil focused play, located on the border of Oklahoma and Kansas.

Concentrate in Core Operating Areas and Build Scale. We plan to continue focusing on our operations in Oklahoma, Texas and the Gulf Coast Basin. Operating in concentrated areas helps us 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.

2012 Financial and Operational Summary

During 2012, we invested $135.2 million in exploratory, development and acquisition activities. We drilled 86 gross exploratory wells and 21 gross development wells realizing an overall success rate of 98%. These activities were financed through our cash flow from operations, cash on hand and borrowings under our bank credit facility. During 2012, our production increased 13% to 34.0 Bcfe, as a result of success in our Oklahoma and Texas drilling programs as well as the successful drilling of our La

Cantera prospect, partially offset by naturally declining production at our Gulf Coast properties. Our estimated proved reserves at December 31, 2012 decreased 14.0% from 2011 as discussed in greater detail below.

Oil and Gas Reserves

Our estimated proved reserves at December 31, 2012 decreased 14.0% from 2011 totaling 1.7 MMBbls of oil, 25.4 Bcfe of natural gas liquids (Ngls) and 193.0 Bcf of natural gas, with a pre-tax present value, discounted at 10%, of the estimated future net revenues based on average prices during 2012 ("PV-10") of $239 million. The decline in our estimated proved reserves during 2012 was primarily the result of production and the significant decrease in the historical 12-month average price per Mcf of natural gas used to calculate our estimated proved reserves, along with the sale of our non-operated Arkansas assets in December 2012. At December 31, 2012, our standardized measure of discounted cash flows, which includes the estimated impact of future income taxes, totaled $232 million. See the reconciliation of PV-10 to the standardized measure of discounted cash flows below. Our standardized measure of discounted cash flows at December 31, 2012 was 24% lower than 2011 as we utilized prices (adjusted for field differentials) for the years ended December 31, 2012 and 2011 as follows:

	12/31/2012	12/31/2011
Oil per Bbl	$102.81	$101.42
Natural gas per Mcf	$2.20	$3.34
Ngl per Mcfe	$6.07	$8.62

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, 2012. Our internal reservoir engineering staff is managed by an individual with 31 years of industry experience as a reservoir and production engineer, including ten years as a reservoir engineering manager with PetroQuest. This individual is responsible for overseeing the estimates prepared by Ryder Scott.

The following table sets forth certain information about our estimated proved reserves as of December 31, 2012:

	Oil (MBbls)	NGL (Mmcfe)	Natural Gas (Mmcf)	Total Mmcfe*
Proved Developed	1,225	20,608	140,307	168,265
Proved Undeveloped	430	4,752	52,661	59,993
Total Proved	1,655	25,360	192,968	228,258

* 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, 2012, our proved undeveloped reserves ("PUDs") totaled 60.0 Bcfe, a 42% decrease from our PUD balance at December 31, 2011. This decrease was due primarily to the 34% decrease in the historical 12-month first day of the month average natural gas price used in computing our reserves, which was $2.20 per Mcf as of December 31, 2012 as compared to $3.34 per Mcf as of December 31, 2011. During 2012, we spent $2.9 million converting 15 Bcfe of PUDs at December 31, 2011 to proved developed reserves at December 31, 2012. PUDs added from extensions and discoveries were primarily the result of successful drilling in our Carthage field in East Texas. Following is an analysis of the change in our PUDs as of December 31, 2012:

	Mmcfe
PUD Balance at December 31, 2011	103,935
PUDs converted to proved developed	(14,997)
PUDs added from revisions or extensions and discoveries	19,463
PUDs removed for 5 year rule	(5,490)
PUDs removed due to low commodity prices	(38,321)
PUDs sold	(4,597)
PUD Balance at December 31, 2012	59,993

Approximately 66% of our PUDs at December 31, 2012 were associated with the future development of our Oklahoma properties. We expect all of our PUDs at December 31, 2012 to be developed over the next five years. At December 31, 2012, we had no PUDs that had been booked for longer than five years. Estimated future costs related to the development of PUDs are expected to total $28.4 million in 2013, $29.0 million in 2014 and $26.5 million in 2015. However, because 88% of our PUDs at December 31, 2012 are comprised of natural gas, the specific timing of the development of PUDs over the next five years is highly dependent upon the prevailing price of natural gas.

The estimated cash flows from our proved reserves at December 31, 2012 were as follows:

	Proved Developed (M$)	Proved Undeveloped (M$)	Total Proved (M$)
Estimated pre-tax future net cash flows (1)	$ 350,284	$ 56,534	$ 406,818
Discounted pre-tax future net cash flows (PV-10) (1)	$ 228,053	$ 11,216	$ 239,269
Total standardized measure of discounted future net cash flows			$ 232,395

(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, 2012:

	Total Proved (M$)
Estimated pre-tax future net cash flows	$ 406,818
10% annual discount	(167,549)
Discounted pre-tax future net cash flows	239,269
Future income taxes discounted at 10%	(6,874)
Standardized Measure of discounted future net cash flows	$ 232,395

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, 2012 and 2011.

	2012		2011	
	Reserves	Production	Reserves	Production
Oklahoma Woodford	146.4	16.3	184.1	12.8
Oklahoma Miss-Lime	2.1	0.2	0.4	—
E. Texas	46.7	6.4	30.9	4.4
S. Texas	2.8	0.4	2.2	0.1
Gulf Coast Basin	30.0	8.7	24.7	10.2
Arkansas (1)	—	2.0	22.6	2.5
Wyoming	0.3	—	0.5	0.2
	228.3	34.0	265.4	30.2

(1) On December 31, 2012, we sold our Arkansas assets for a net cash purchase price of $9.2 million.

Oklahoma

During late 2006, we began our initial drilling program to evaluate the Woodford Shale formation on a substantial portion of our Oklahoma acreage. During 2012, we continued our evaluation of the Woodford Shale as we drilled and participated in 46 gross wells, achieving a 98% success rate. In total, we invested $40.8 million during 2012 acquiring prospective Woodford Shale acreage and drilling and completing wells. In addition, during 2012 we utilized $28.5 million of drilling carry under the amended JDA and plan to continue utilizing the drilling carry during 2013 under the second phase of the amended JDA. Average daily production from our Oklahoma properties during 2012 totaled 45 MMcfe per day, a 28% increase from 2011 average daily production. We experienced negative revisions to our proved reserves as a result of lower average prices, which resulted in a 20% decrease in our estimated proved reserves. Partially offsetting this negative impact was the addition of approximately 27 Bcfe of estimated proved reserves from our drilling program during the year. We have allocated approximately 37% of our 2013 capital budget to operations in the Woodford Shale as we expect to operate the drilling of approximately 23 gross wells, 15 of which will target liquids rich gas, as well as obtain 3-D seismic data over acreage recently acquired to target liquids rich gas.

As of December 31, 2012, we had invested $16.5 million to acquire approximately 24,000 net acres of Mississippian Lime acreage in northern Oklahoma and southern Kansas. During 2012, we invested $26 million as we began evaluating this prospective acreage through coring and seismic work and the drilling of nine gross exploratory wells, achieving an 89% success rate. During 2012, we utilized $11.6 million of drilling carry under the amended JDA. We have allocated approximately 10% of our 2013 capital budget to explore this primarily oil focused trend. We plan to acquire 3-D seismic data over our acreage positions and drill three gross Mississippian Lime wells in 2013. We expect to be able to utilize the 3-D data later in 2013 to assist in the future development of this asset.

Gulf Coast Basin

During 2012, we drilled two gross wells in the Gulf Coast Basin, achieving a 100% success rate. In total, we invested $21.0 million in this area during 2012. Production from this area decreased 16% from 2011 totaling 23.7 MMcfe per day in 2012 due to natural production declines. However, production from our second discovery well in our La Cantera prospect commenced during September 2012 with a third acceleration well at La Cantera currently drilling. Our estimated proved reserves in this area increased 21% from 2011 primarily as a result of success in the 2012 drilling program. We have allocated approximately 41% of our 2013 capital budget to various drilling and re-completion projects in the Gulf Coast Basin.

East Texas

During 2012, we invested $23.7 million in our East Texas properties as we drilled and participated in six gross wells, achieving a 100% success rate. Net production from our East Texas assets averaged 17.4 MMcfe per day during 2012, a 45% increase from 2011 average daily production and our estimated proved reserves increased 51% from 2011, primarily as a result of successful drilling in our Carthage field. We have allocated approximately 11% of our 2013 capital budget to drilling and facility enhancements in our Carthage field.

South Texas

During 2012, we invested $14.7 million in our South Texas properties as we drilled five gross wells, all of which were successful. Net production from our South Texas assets averaged 175 BOE per day during 2012, a 181% increase as compared to 2011 and our estimated proved reserves increased 23% from 2011. We are currently evaluating our plans for 2013, including the possibility of divestment.

Arkansas

During 2012, we participated in 39 gross wells in the Fayetteville Shale, all of which were successful. In total, we invested $1.2 million in Arkansas during 2012. Production during 2012 totaled 5.4 MMcfe per day, a 20% decrease from 2011. We sold this non-operated asset on December 31, 2012 for a net cash purchase price of $9.2 million.

Markets and Customers

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

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

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

A portion of the production that we operate in Oklahoma is committed to a firm transportation agreement. Under the terms of the agreement we must deliver 7.6 Bcf of natural gas during the period January 1 through October 31, 2013. Based upon our current proved reserves and production, we expect that this commitment will be met.

In view of the many uncertainties affecting the supply and demand for oil, natural gas and refined petroleum products, we are unable to predict future oil and natural gas prices and demand or the overall effect such prices and demand will have on the Company. During 2012, one customer accounted for 30%, one accounted for 17%, and one accounted for 12% of our oil and natural gas revenue. During 2011, one customer accounted for 20%, one accounted for 18%, one accounted for 15% and one accounted for 11% of our oil and natural gas revenue. During 2010, one customer accounted for 19%, two accounted for 17% each and one accounted for 10% 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. Only two core areas, East Texas and Oklahoma, which includes primarily Woodford Shale reserves, represented greater than 15% of our total estimated proved reserves.

	Year Ended December 31,		
	2012	2011	2010
Production:			
Oil (Bbls):			
East Texas	87,368	96,923	102,410
Oklahoma - Woodford	171	145	71
Other	433,051	475,028	560,821
Total Oil (Bbls)	520,590	572,096	663,302
Gas (Mcf):			
East Texas	4,360,290	2,871,284	2,206,266
Oklahoma - Woodford	15,349,219	12,736,622	10,577,414
Other	7,756,719	8,855,027	11,717,860
Total Gas (Mcf)	27,466,228	24,462,933	24,501,540
NGL (Mcfe):			
East Texas	1,479,441	924,668	632,875
Oklahoma - Woodford	947,935	553	683
Other	939,398	1,362,625	1,836,313
Total NGL (Mcfe)	3,366,774	2,287,846	2,469,871
Total Production (Mcfe):			
East Texas	6,363,939	4,377,490	3,453,601
Oklahoma - Woodford	16,298,180	12,738,045	10,578,523
Other	11,294,423	13,067,820	16,919,099
Total Production (Mcfe)	33,956,542	30,183,355	30,951,223
Average sales prices (1):			
Oil (per Bbl):			
East Texas	$ 104.42	$ 101.59	$ 77.61
Oklahoma - Woodford	$ 92.53	$ 89.61	$ 69.62
Other	$ 106.15	$ 106.09	$ 79.82
Total Oil (per Bbl)	$ 105.85	$ 105.33	$ 79.47
Gas (per Mcf)			
East Texas	$ 2.82	$ 3.92	$ 4.32
Oklahoma - Woodford	$ 1.51	$ 2.42	$ 2.80
Other	$ 2.73	$ 3.84	$ 4.31
Total Gas (per Mcf)	$ 2.06	$ 3.11	$ 3.66
NGL (per Mcfe)			
East Texas	$ 5.72	$ 8.19	$ 6.38
Oklahoma - Woodford	$ 4.49	$ 5.15	$ 3.79
Other	$ 8.32	$ 10.41	$ 8.26
Total NGL (per Mcfe)	$ 6.10	$ 9.51	$ 7.78
Total Per Mcfe:			
East Texas	$ 4.69	$ 6.55	$ 6.23
Oklahoma - Woodford	$ 1.69	$ 2.42	$ 2.80
Other	$ 6.64	$ 7.54	$ 6.52
Total Per Mcfe	$ 3.90	$ 5.24	$ 5.22
Average Production Cost per Mcfe (2):			
East Texas	$ 1.56	$ 2.12	$ 2.56
Oklahoma - Woodford	$ 0.49	$ 0.76	$ 0.71
Other	$ 1.86	$ 1.50	$ 1.34
Total Average Production Cost per Mcfe	$ 1.15	$ 1.28	$ 1.26

(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, 2012:

	Gross	Net
Productive Wells:		
Oil:		
East Texas	3	2.53
Oklahoma - Woodford	—	—
Other	47	18.46
	50	20.99
Gas:		
East Texas	105	68.73
Oklahoma - Woodford	172	50.57
Other	470	132.12
	747	251.42
Total	797	272.41

Of the 797 gross productive wells at December 31, 2012, 2 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.

	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Exploration:						
Productive	84	15.87	94	18.15	82	9.55
Non-productive	2	0.84	1	0.50	3	0.76
Total	86	16.71	95	18.65	85	10.31
Development:						
Productive	21	4.88	23	1.33	17	1.50
Non-productive	—	—	—	—	—	—
Total	21	4.88	23	1.33	17	1.50

In 2012, 31 gross (7.49 net) exploratory and 15 gross (4.78 net) development wells were drilled in the Woodford Shale. In 2011, 35 gross (9.94 net) exploratory and one gross (.05 net) development wells were drilled in the Woodford Shale. In 2010, 19 gross (7.32 net) exploratory and 1 gross (.81 net) development wells were drilled in the Woodford Shale. One Woodford Shale well during 2012 was non-productive.

At December 31, 2012, we had 17 gross (6.61 net) wells in progress in Oklahoma.

Leasehold Acreage

The following table shows our approximate developed and undeveloped (gross and net) leasehold acreage as of December 31, 2012:

	Leasehold Acreage			
	Developed		Undeveloped	
	Gross	Net	Gross	Net
Kansas	—	—	4,091	2,046
Louisiana	4,489	1,455	8,829	5,867
Mississippi	721	721	—	—
Oklahoma	69,308	38,646	99,599	46,182
Texas	42,000	22,768	8,441	4,449
Wyoming	2,720	680	3,319	830
Federal Waters	39,283	23,611	7,124	7,124
Total	158,521	87,881	131,403	66,498

Leases covering 18% of our net undeveloped acreage are scheduled to expire in 2013, 19% in 2014, 16% in 2015 and 47% thereafter. Of the acreage subject to leases scheduled to expire during 2013, less than 3% relates to undeveloped acreage in Texas and Wyoming where we do not anticipate any further drilling. We expect to hold the majority of the remaining acreage scheduled to expire in 2013 through drilling or lease extensions.

Title to Properties

We believe that the title to our oil and gas properties is good and defensible in accordance with standards generally accepted in the oil and gas industry, subject to such exceptions which, in our opinion, are not so material as to detract substantially from the use or value of such 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 ("NGPA") and 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") and 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 ongoing economic downturn on natural gas supply and demand fundamentals has resulted in extremely volatile natural gas prices, which is expected to continue.

On August 8, 2005, the Energy Policy Act of 2005 (the "2005 EPA") was signed into law. This comprehensive act contains many provisions that will 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. We do not 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. We do not anticipate that we will be affected any differently than other producers of natural gas.

Sales and Transportation of Crude Oil. 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. 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 BOEMRE, BOEM or BSEE, pursuant to the OCSLA. The BOEMRE and its successors, 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.

On January 19, 2011, the U.S. Department of the Interior announced that it would divide offshore oil and gas responsibilities among three separate agencies, with the reorganization to be completed in 2011. The Department of the Interior first created the Office of Natural Resources Revenue to manage revenue collection on October 1, 2010. Effective October 1, 2011, the remaining functions of BOEMRE were split into two federal bureaus, the BOEM, which 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, which 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. Consequently, after October 1, 2011, we are required to interact with two newly formed federal bureaus to obtain approval of our exploration and development plans and issuance of drilling permits, which may result in added plan approval or drilling permit delays as the functions of the former BOEMRE are fully divested and implemented in the two federal bureaus. At this time, we cannot predict the impact that this reorganization, or future regulations of enforcement actions taken by the new agencies, may have on our operations. Our federal oil and natural gas leases are awarded based on competitive bidding and contain relatively standardized terms. These leases require compliance with detailed BOEMRE regulations and orders that are subject to interpretation and change by the BOEM or BSEE. The BOEMRE has promulgated other 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 16 for more information on new regulations.

To cover the various obligations of lessees on the Outer Continental Shelf (the "OCS"), the BOEMRE and its successors generally require that lessees have substantial net worth or post bonds or other acceptable assurances that such obligations will be satisfied. The cost of these bonds or assurances can be substantial and there is no assurance that they can be obtained in all cases. We are currently exempt from supplemental bonding requirements. As many regulations are being reviewed, we may be subject to supplemental bonding requirements in the future. 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.

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 BOEMRE has been in the past, and the BOEM and the BSEE will be in the future, 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 has periodically 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 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 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 in 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, plants and other facilities for extracting, transporting, processing, treating 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, installation and operation of 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 other 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 other 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, Ngls, 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.

Oil Pollution Act. The Oil Pollution Act of 1990 (the "OPA") and regulations thereunder impose a variety of regulations 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 a federal safety, construction or operating regulation. 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 $75 million, and lesser limits for some vessels depending upon their size. The regulations promulgated under OPA impose proof of financial responsibility requirements that can be satisfied through insurance, guarantee, indemnity, surety bond, letter of credit, qualification as a self-insurer, or a combination thereof. The amount of financial responsibility required depends upon a variety of factors including the type of facility or vessel, its size, storage capacity, oil throughput, proximity to sensitive areas, type of oil handled, history of discharges and other factors. We carry insurance coverage to meet these obligations, which we believe is customary for comparable companies in our industry. A failure to comply with OPA's requirements or inadequate cooperation during a spill response action may subject a responsible party to civil or criminal enforcement actions.

As a result of the explosion and sinking of the Deepwater Horizon drilling rig in the Gulf of Mexico in April 2010, the U.S. Congress has considered legislation that could increase our obligations and potential liability under the OPA, including by eliminating the current cap on liability for damages and by increasing minimum levels of financial responsibility. It is uncertain whether, and in what form, such legislation may ultimately be adopted. 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. 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. Moreover, 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. The USEPA published a progress report on this study in December 2012 and a final draft report will be delivered in 2014. Additionally, the Bureau of Land Management ("BLM") proposed to regulate the use of hydraulic fracturing on federal and tribal lands, but following extensive public comment on the proposals, announced it would issue an improved proposal before finalizing new rules. The revised proposal is expected to address disclosure of fluids used in the fracturing process, integrity of well construction, and the management and disposal of wastewater that flows back from the drilling process. Some states now regulate utilization of hydraulic fracturing and others are in the process of developing, or are considering development of, such rules. 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 regulatory 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 and that, if a particular permit application were denied, we would have enough permitted or permittable capacity to continue our operations without a material adverse effect on any particular producing field.

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 new 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. Further, apart from these developments, recent judicial decisions that have not precluded certain state tort claims alleging property damage to proceed against GHG emissions sources may increase the Company's litigation risk for such claims. 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.

USEPA has finalized new 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) after January 1, 2015. Other new requirements, many effective in 2012, involve tighter standards for emissions associated with gas production, storage and transport. 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 ("CMP") 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 EPA 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 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 48,400 square feet of leased space, with exploration offices in Houston, Texas and Tulsa, Oklahoma, in approximately 5,500 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 116 full-time employees as of February 7, 2013. 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 report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed 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 natural gas prices have been significantly depressed since the middle of 2008. An extended decline in the prices of oil and natural gas would likely have a material adverse effect on our financial condition, liquidity, ability to meet our financial obligations and results of operations.

Our future financial condition, revenues, results of operations, profitability and future growth, and the carrying value of our oil and natural gas properties depend primarily on the prices we receive for our oil and natural gas production. Our ability to maintain or increase our borrowing capacity and to obtain additional capital on attractive terms also substantially depends upon oil and natural gas prices. Prices for natural gas have been significantly depressed since the middle of 2008 and future oil and natural gas prices are subject to large fluctuations in response to a variety of 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 Federal Energy Regulatory Commission;
- 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. An extended decline in oil and natural gas prices may adversely affect our financial condition, liquidity, ability to meet our financial obligations and results of operations. Lower prices have reduced and may further reduce the amount of oil and natural gas that we can produce economically and has required and may require us to record additional ceiling test write-downs. 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.

We have a substantial amount of indebtedness, which may adversely affect our cash flow and our ability to operate our business, remain in compliance with debt covenants and make payments on our debt.

As of December 31, 2012, the aggregate amount of our outstanding indebtedness, net of cash on hand, was $185.1 million, which 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 10% senior notes due 2017, which we refer to as our 10% 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 $15 million per year for interest on our 10% notes alone, and to pay quarterly dividends, if declared by our Board of Directors, on our 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% 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% 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% 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% 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% 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.

Declining general economic, business or industry conditions may have a material adverse effect on our results of operations, liquidity and financial condition.

Concerns over global economic conditions, energy costs, geopolitical issues, inflation, the availability and cost of credit, the United States mortgage market and a declining real estate market in the United States have contributed to increased economic uncertainty and diminished expectations for the global economy. These factors, combined with volatile prices of oil and natural gas, declining business and consumer confidence and increased unemployment, have precipitated an economic slowdown and a recession. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad continues to deteriorate, demand for petroleum products could diminish, which could impact the price at which we can sell our oil, natural gas and natural gas liquids, affect the ability of our vendors, suppliers and customers to continue operations and ultimately adversely impact our results of operations, liquidity and financial condition.

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. During 2012 and 2011, we recognized approximately $137.1 million and $18.9 million, respectively, in ceiling test write-downs as a result of the decline in commodity prices.

We review the net capitalized costs of our properties quarterly, using, effective for fiscal periods ending on or after December 31, 2009, 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 unproved 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 unproved property values, or if estimated future development costs increase. We may experience further ceiling test write-downs or other impairments in the future. In addition, any future ceiling test cushion would be subject to fluctuation as a result of acquisition or divestiture activity.

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 our 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 non-core 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.

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% 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% 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. 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% 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% notes. A default, if not cured or waived, could result in all indebtedness outstanding under our bank credit facility and our 10% 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 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 one quarter 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 one quarter 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, 2012, approximately one quarter of our production and approximately 13% of our 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.

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.

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 Macondo well explosion and ensuing oil spill could have broad adverse consequences affecting our operations in the Gulf of Mexico, some of which may be unforeseeable.

In April 2010, there was a fire and explosion aboard the rig drilling the Macondo well operated by another company in ultra-deep water in the U.S. Gulf of Mexico. As a result of the explosion and ensuing fire, the rig sank, causing loss of life, and created a major oil spill that produced economic, environmental and natural resource damage in the U.S. Gulf Coast region. In response to the explosion and spill, there have been many proposals by governmental and private constituencies to address the direct impact of the disaster and to prevent similar disasters in the future. Beginning in May 2010, the U.S. Department of the Interior, initially through its federal Minerals Management Service (the "MMS"), which was subsequently renamed the Bureau of Ocean Energy Management, Regulation and Enforcement (the "BOEMRE") in June 2010, issued a series of "Notices to Lessees and Operators" ("NTLs"), imposing a variety of new safety measures and permitting requirements, and implementing a moratorium on deepwater drilling activities in the U.S. Gulf of Mexico that effectively shut down deepwater drilling activities until the moratorium was lifted by Secretary of the Interior Ken Salazar in October 2010. Despite the fact that the drilling moratorium was lifted, this spill and its aftermath have led to delays in obtaining drilling permits from the BOEMRE. Effective October 1, 2011, the BOEMRE was split into two federal bureaus, the Bureau of Ocean Energy Management (the "BOEM"), which 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 Bureau of Safety and Environmental Enforcement (the "BSEE"), which 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. Consequently, after October 1, 2011, we will be required to interact with two newly formed federal bureaus to obtain approval of our exploration and development plans and issuance of drilling permits, which may result in added plan approval or drilling permit delays as the functions of the former BOEMRE are fully divested and implemented in the two federal bureaus. While legislation was introduced and passed in the U.S. House of Representatives to expedite the process for offshore permits including limitations on the timeframe for environmental and judicial review, there is no guarantee that this or similar legislation will pass in the U.S. Senate.

In addition to the drilling restrictions, new safety measures and permitting requirements already issued by the BOEMRE, there have been numerous additional proposed changes in laws, regulations, guidance and policy in response to the Macondo well explosion and oil spill that could affect our operations and cause us to incur substantial losses or expenditures. Implementation of any one or more of the various proposed responses to the disaster could materially adversely affect operations in the U.S. Gulf of Mexico by raising operating costs, increasing insurance premiums, delaying drilling operations and increasing regulatory costs, and, further, could lead to a wide variety of other unforeseeable consequences that make operations in the U.S. Gulf of Mexico more difficult, more time consuming, and more costly. For example, during the previous session of Congress, a variety of amendments to the OPA, were proposed in response to the Macondo well incident. The OPA and regulations adopted pursuant to the OPA impose a variety of requirements related to the prevention of and response to oil spills into waters of the United States, including the Outer Continental Shelf, which includes the U.S. Gulf of Mexico where we have offshore operations. The OPA subjects operators of offshore leases and owners and operators of oil handling facilities to strict joint and several liability for all containment and cleanup costs and certain other damages arising from a spill, including, but not limited to, the costs of responding to a release of oil, natural resource damages, and economic damages suffered by persons adversely affected by an oil spill. The OPA also requires owners and operators of offshore oil production facilities to establish and maintain evidence of financial responsibility to cover costs that could be incurred in responding to an oil spill. The OPA currently requires a minimum financial responsibility demonstration of $35 million for companies operating on the Outer Continental Shelf, although the Secretary of Interior may increase this amount up to $150 million in certain situations. Legislation was proposed in a previous session of Congress to amend the OPA to increase the minimum level of financial responsibility to $300 million or more and there exists the possibility that similar legislation could be introduced and adopted during the current session of Congress. If the OPA is amended during the current session of Congress to increase the minimum level of financial responsibility to $300 million, we may experience difficulty in providing financial assurances sufficient to comply with this requirement. If we are unable to provide the level of financial assurance required by the OPA, we may be forced to sell our properties or operations located on the Outer Continental Shelf or enter into partnerships with other companies that can meet the increased financial responsibility requirement, and any such developments could have an adverse effect on the value of our offshore assets and the results of our operations. We cannot predict at this time whether the OPA will be amended or whether the level of financial responsibility required for companies operating on the Outer Continental Shelf will be increased.

Regulatory requirements imposed by the BOEMRE, BOEM or BSEE could significantly delay our ability to obtain permits to drill new wells in offshore waters.

Subsequent to the Macondo well incident in the U.S. Gulf of Mexico, the BOEMRE issued a series of NTLs and other regulatory requirements imposing new standards and permitting procedures for new wells to be drilled in federal waters of the Outer Continental Shelf. These requirements include the following:

- The Environmental NTL, which imposes new and more stringent requirements for documenting the environmental impacts potentially associated with the drilling of a new offshore well and significantly increases oil spill response requirements.

- The Compliance and Review NTL, which imposes requirements for operators to secure independent reviews of well design, construction and flow intervention processes, and also requires certifications of compliance from senior corporate officers.

- The Drilling Safety Rule, which prescribes tighter cementing and casing practices, imposes standards for the use of drilling fluids to maintain wellbore integrity, and stiffens oversight requirements relating to blowout preventers and their components, including shear and pipe rams.

- The Workplace Safety Rule, which requires operators to have a comprehensive safety and environmental management system ("SEMS") in order to reduce human and organizational errors as root causes of work-related accidents and offshore spills.

On September 14, 2011, BOEMRE issued proposed rules that would amend the Workplace Safety Rule by requiring the imposition of certain added safety procedures to a company's SEMS not covered by the original rule and revising existing obligations that a company's SEMS be audited by requiring the use of an independent third party auditor who has been pre-approved by the agency to perform the auditing task. These proposed amendments have not yet been implemented. Moreover, effective October 1, 2011, the BOEMRE was split into two separate federal bureaus, the BOEM and the BSEE. As the new standards and procedures are being integrated into the existing framework of offshore regulatory programs, we anticipate that there may be increased costs associated with regulatory compliance and delays in obtaining permits for other operations such as recompletions, workovers and abandonment activities.

We are unsure what long-term effect, if any, the BOEMRE's, BOEM's or BSEE's additional regulatory requirements and permitting procedures will have on our offshore operations. Consequently, we may be subject to a variety of unforeseen adverse consequences arising directly or indirectly from the Macondo well incident.

Regulatory requirements imposed by the BOEMRE, BOEM or BSEE could significantly impact our estimates of future asset retirement obligations from period to period.

We are responsible for plugging and abandoning wellbores and decommissioning associated platforms, pipelines and facilitates on our oil and natural gas properties. In addition to the NTLs discussed previously, the BOEMRE issued NTL No. 2010-G05, effective October 15, 2010, which establishes a more stringent regimen for the timely decommissioning of what is known as "idle iron"-wells, platforms and pipelines that are no longer producing or serving exploration or support functions related to an operator's lease-in the U.S. Gulf of Mexico. This NTL sets forth more stringent standards for decommissioning timing requirements by applying the requirement that any well that has not been used during the past five years for exploration or production on active leases and is no longer capable of producing in paying quantities must be permanently plugged or temporarily abandoned within three years. Plugging or abandonment of wells may be delayed by two years if all of the well's hydrocarbon and sulphur zones are appropriately isolated. Similarly, platforms or other facilities that are no longer useful for operations must be removed within five years of the cessation of operations. The triggering of these plugging, abandonment and removal activities under what may be viewed as an accelerated schedule in comparison to the industry's historical decommissioning efforts may serve to increase, perhaps materially, our future plugging, abandonment and removal costs, which may translate into a need to increase our estimate of future asset retirement obligations required to meet such increased costs. For additional details relating to our asset retirement obligations, please read Note 6 to our audited consolidated financial statements.

BSEE has also issued several NTLs imposing or enhancing requirements related to oil spill prevention and reporting. These NTLs expand guidelines for Oil Spill Response Plans, specify expected content of written oil discharge reports to be submitted following an incident, and clarify calculations to be made of various anticipated pressures prior to production.

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. The USEPA published a progress report on this study in December 2012, and the final draft report is scheduled for completion by 2014. USEPA has also finalized new 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) after January 1, 2015. Other new requirements, many effective in 2012, involve tighter standards for emissions associated with gas production, storage and transport. Additionally, the Bureau of Land Management ("BLM") has proposed rules to regulate the use of hydraulic fracturing on federal and tribal lands, but following extensive public comment on the proposals, announced it would issue an improved proposal before finalizing new rules. The revised proposal is expected to address disclosure of fluids used in the fracturing process, integrity of well construction, and the management and disposal of wastewater that flows back from the drilling process.

A number of states, including Louisiana, Texas and Wyoming, 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 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 may be imposed to address such concerns.

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 or state legislation or regulation regarding hydraulic fracturing, management of drilling fluids or well integrity requirements, any new federal or state restrictions imposed on such 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 and implementation of new statutory and regulatory requirements for derivative transactions could have an adverse impact on our ability to hedge risks associated with our business and increase the working capital requirements to conduct these activities.

In July 2010, federal legislation known as the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, was enacted. The Dodd-Frank Act provides for new statutory and regulatory requirements for derivative transactions, including oil and natural gas hedging transactions. Among other things, the Dodd-Frank Act provides for the creation of position limits for certain derivatives transactions, as well as requiring certain transactions to be cleared on exchanges for which cash collateral will be required. In October 2011, the Commodities Futures Trading Commission, or the CFTC, approved final rules that establish position limits for futures contracts on 28 physical commodities, including four energy commodities, and swaps, futures and options that are economically equivalent to those contracts. The rules provide an exemption for "bona fide hedging" transactions or positions, but this exemption is narrower than the exemption under existing CFTC position limit rules. These newly approved CFTC position limits rules were vacated by the United States District Court for the District of Columbia in September 2012, although the CFTC has stated that it will appeal the District Court's decision.

It is not possible at this time to predict with certainty the full effect of the Dodd-Frank Act and CFTC rules on us and the timing of such effects. The Dodd-Frank Act may require us to comply with margin requirements and with certain clearing and trade-execution requirements if we do not satisfy certain specific exceptions. The Dodd-Frank Act may also require the counterparties to our derivatives contracts to transfer or assign some of their derivatives contracts to a separate entity, which may not be as creditworthy as the current counterparty. Depending on the rules adopted by the CFTC or similar rules that may be adopted by other regulatory bodies, we might in the future be required to provide cash collateral for our commodities hedging transactions under circumstances in which we do not currently post cash collateral. Posting of such additional cash collateral could impact liquidity and reduce our cash available for capital expenditures. A requirement to post cash collateral could therefore reduce our ability to execute hedges to reduce commodity price uncertainty and thus protect cash flows. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable.

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.

The U.S. President's Fiscal Year 2013 Budget Proposal includes provisions that would, if enacted, make significant changes to U.S. tax laws applicable to oil and natural gas exploration and production companies. These changes include, but are not limited to:

- the repeal of the limited percentage depletion allowance for oil and natural gas production in the United States;
- the elimination of current deductions for intangible drilling and development costs;
- the elimination of the deduction for certain domestic production activities; and
- an extension of the amortization period for certain geological and geophysical expenditures.

Members of the U.S. Congress have considered similar changes to the existing federal income tax laws that affect oil and natural gas exploration and production companies. It is unclear whether these or similar changes will be enacted. The passage of this legislation or any similar changes in federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to U.S. oil and natural gas exploration and development. Any such changes could have an adverse effect on our financial position, 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.

Our estimates of proved reserves have been prepared under revised SEC rules which went into effect for fiscal years ending on or after December 31, 2009, which may make comparisons to prior periods difficult and could limit our ability to book additional proved undeveloped reserves in the future.

This Form 10-K presents estimates of our proved reserves as of December 31, 2012, which have been prepared and presented under revised SEC rules. These revised rules were effective for fiscal years ending on or after December 31, 2009, and require SEC reporting companies to prepare their reserve estimates using revised reserve definitions and revised pricing based on twelve-month unweighted first-day-of-the-month average pricing. The previous rules required that reserve estimates be calculated using last-day-of-the-year pricing. As a result of these changes, direct comparisons to our reserve amounts reported prior to the year ending on December 31, 2009 may be more difficult.

Another impact of the revised SEC rules is a general requirement 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 revised rule 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 drill on those reserves within the required five-year time frame. We removed approximately 5.5 Bcfe of proved undeveloped reserves in 2012 as a result of the five year rule.

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 2012 production was approximately 7% greater than amounts projected in our 2011 reserve report. We cannot assure you that these differences will not be material in the future.

Approximately 26% of our estimated proved reserves at December 31, 2012 are undeveloped and 6% 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 development will occur as scheduled or that the actual results will be as estimated. In addition, the recovery of undeveloped reserves 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, 2012 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 timing of both the production and the expenses from the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves and their present value. 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.

Hedging production may limit potential gains from increases in commodity prices or result in losses.

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, 2012 are in the form of a three-way costless collar and a straight swap placed with the commodity trading branch of JPMorgan Chase Bank which participates in our bank credit facility. We cannot assure you that this or future counterparties will not become credit risks in the future. Hedging arrangements expose us to risks in some circumstances, including situations when the counterparty to the hedging contract defaults on the contractual obligations or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received. These hedging arrangements may limit the benefit we could receive from increases in the market or spot prices for oil and natural gas. Oil and natural gas hedges increased our total oil and gas sales by approximately $9.1 million, $2.4 million and $17.5 million during 2012, 2011 and 2010, respectively. 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.

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.

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 standards in environmental legislation and regulation is likely to continue. 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 and further 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.

The Oil Pollution Act of 1990 imposes a variety of regulations on "responsible parties" related to the prevention of oil spills. The implementation of new, or the modification of existing, environmental laws or regulations, including regulations promulgated pursuant to the Oil Pollution Act, could have a material adverse impact on us.

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.

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 other energy companies, has been and may continue to be highly volatile. During 2012, the sales price of our stock ranged from a low of $4.26 per share (on June 4, 2012) to a high of $7.39 per share (on January 5, 2012). 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.

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, 2012, we had reserved approximately 1.9 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. 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 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;

- provisions that directors may be removed only for cause, and then only on approval of holders of a majority of the outstanding voting 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, 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 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.

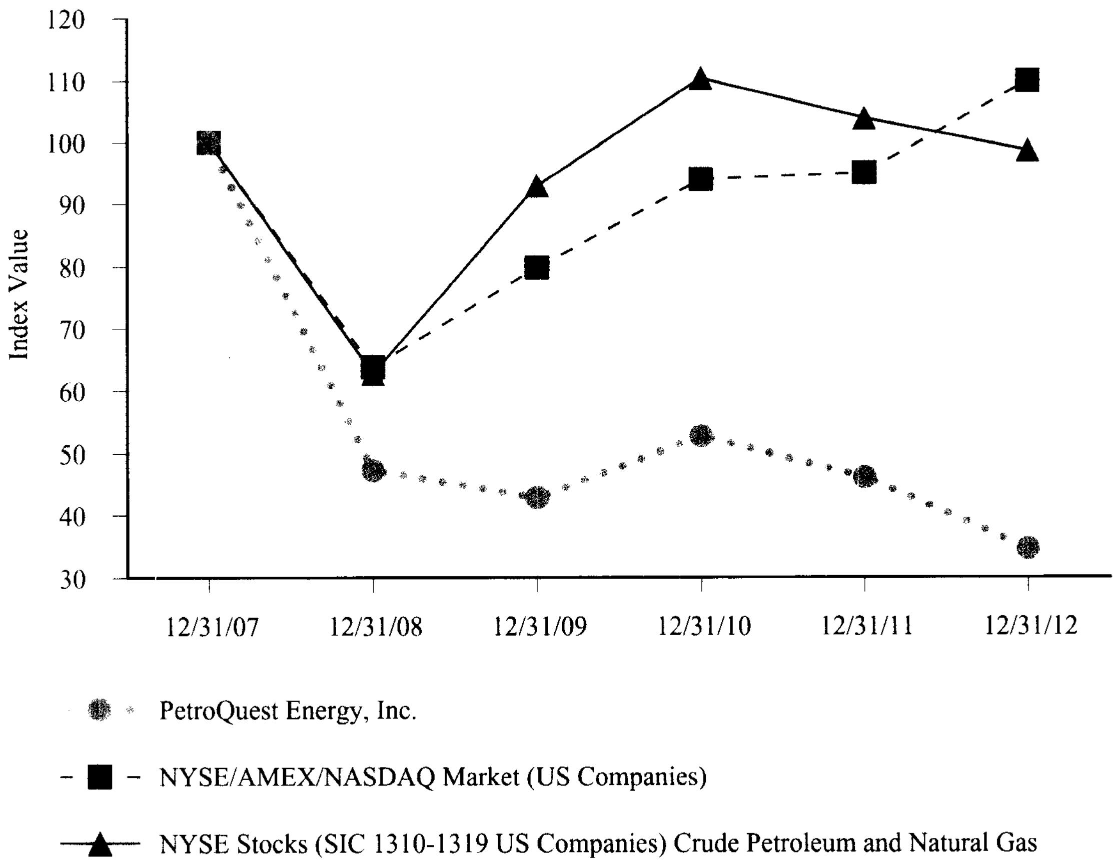
PART II

Item 5.

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 and the NYSE Stocks—Crude Petroleum and Natural Gas Index, for the five years ended December 31, 2012.

Comparison of 5 Year Cumulative Total Return
Assumes Initial Investment of $100
December 2012



	PetroQuest Energy, Inc.	NYSE/AMEX/NASDAQ Market (US Companies)	NYSE Stocks (SIC 1310-1319 US Companies) Crude Petroleum and Natural Gas
12/31/2007	$100.00	$100.00	$100.00
12/31/2008	47.26	63.85	62.78
12/31/2009	42.86	79.87	92.97
12/31/2010	52.65	94.00	110.35
12/31/2011	46.15	95.01	103.83
12/31/2012	34.61	109.87	98.65

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:

	High	Low
2011		
1st Quarter	$ 9.75	$ 6.92
2nd Quarter	9.60	6.21
3rd Quarter	8.70	5.48
4th Quarter	8.11	4.72
2012		
1st Quarter	$ 7.39	$ 5.41
2nd Quarter	6.46	4.26
3rd Quarter	7.05	4.82
4th Quarter	7.00	4.69

As of February 28, 2013, there were 302 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 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, 2012.

	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, 2012	20,669	$ 6.86	—	—
November 1—November 30, 2012	—	$ —	—	—
December 1—December 31, 2012	—	$ —	—	—

(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, 2012 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,				
	2012 (1)	2011 (2)	2010	2009 (3)	2008 (4)
	(in thousands except per share and per Mcfe data)				
Average sales price per Mcfe	$ 4.17	$ 5.32	$ 5.78	$ 6.39	$ 9.13
Revenues	141,591	160,700	179,263	218,684	311,649
Net income (loss) available to common stockholders	(137,218)	5,409	41,987	(95,330)	(102,100)
Net income (loss) available to common stockholders per share:					
Basic	(2.20)	0.08	0.67	(1.72)	(2.08)
Diluted	(2.20)	0.08	0.66	(1.72)	(2.08)
Oil and gas properties, net	333,946	405,351	312,940	321,875	512,861
Total assets	433,403	516,166	439,517	410,459	670,249
Long-term debt	200,000	150,000	150,000	178,267	278,998
Stockholders' equity	87,591	222,390	208,162	162,105	237,487

(1) The year ended December 31, 2012 includes a pre-tax ceiling test write-down of $137.1 million.
(2) The year ended December 31, 2011 includes a pre-tax ceiling test write-down of $18.9 million.
(3) The year ended December 31, 2009 includes a pre-tax ceiling test write-down of $156.1 million.
(4) The year ended December 31, 2008 includes a pre-tax ceiling test write-down of $266.2 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 operations in Oklahoma, Texas, the Gulf Coast Basin and Wyoming. 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 in 1985 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 in Oklahoma, Wyoming and Texas through a combination of selective acquisitions and drilling activity. Beginning in 2003 with our acquisition of the Carthage Field in Texas through 2012, we have invested approximately $998 million into growing our longer life assets. During the nine year period ended December 31, 2012, we have realized a 95% drilling success rate on 878 gross wells drilled. Comparing 2012 metrics with those in 2003, the year we implemented our diversification strategy, we have grown production by 252% and estimated proved reserves by 174%. At December 31, 2012, 87% of our estimated proved reserves and 75% of our 2012 production were derived from our longer life assets.

Gas prices have remained weak since late-2008. As a result of the impact of low natural gas prices on our revenues and cash flow, we have focused on growing our reserves and production through a balanced drilling budget with an increased emphasis on growing our oil and natural gas liquids production. In May 2010, we entered into the Woodford joint development agreement ("JDA"), which provided us with $85 million in cash during 2010 and 2011, along with a drilling carry that we have utilized since May 2010 to enhance economic returns by reducing our share of capital expenditures in the Woodford and Mississippian Lime.

As a result of the JDA and the success of our drilling programs, we have grown our estimated proved reserves by 18% and production by 10% since 2010, while maintaining our long-term debt 28% below 2008 levels.

During February 2012, we amended our JDA to accelerate the entry into Phase 2 of the drilling program effective March 1, 2012 and modify the drilling carry ratio. Under the amended JDA, the Phase 2 drilling carry was expanded to provide for development in both the Mississippian Lime and Woodford Shale plays whereby we will pay 25% of the cost to drill and complete wells and receive a 50% ownership interest. The Phase 2 drilling carry is subject to extensions in one-year intervals and as of December 31, 2012, approximately $70.7 million remained available. See "Liquidity and Capital Resources-Source of Capital: Joint Ventures".

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 property and our effective borrowing rate.

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 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.

At December 31, 2012, 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 $2.21 per Mcf of natural gas, $102.81 per barrel of oil, and $6.07 per Mcfe of Ngl. As a result of lower natural gas prices and their negative impact on certain of our longer-lived estimated proved reserves and estimated future net cash flows, we recognized ceiling test write-downs of $137.1 million and $18.9 million during the twelve months ended December 31, 2012 and 2011, respectively. Our cash flow hedges in place decreased the ceiling test write-downs by approximately $2.2 million and $3.9 million during 2012 and 2011, respectively.

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 decline, 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. 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 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 prices at which the hedges will be settled. At December 31, 2012, our derivative instruments, with the exception of a three-way collar contract for 2013 natural gas production, were designated effective cash flow hedges.

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

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,		
	2012	2011	2010
Production:			
Oil (Bbls)	520,590	572,096	663,302
Gas (Mcf)	27,466,228	24,462,933	24,501,540
Ngl (Mcfe)	3,366,774	2,287,846	2,469,871
Total Production (Mcfe)	33,956,542	30,183,355	30,951,223
Sales:			
Total oil sales	$ 56,635,786	$ 60,064,426	$ 52,715,434
Total gas sales	63,535,262	78,664,373	107,117,320
Total ngl sales	21,262,236	21,756,917	19,205,726
Total oil and gas sales	$ 141,433,284	$ 160,485,716	$ 179,038,480
Average sales prices:			
Oil (per Bbl)	$ 108.79	$ 104.99	$ 79.47
Gas (per Mcf)	2.31	3.22	4.37
Ngl (per Mcfe)	6.32	9.51	7.78
Per Mcfe	4.17	5.32	5.78

The above sales and average sales prices include increases (reductions) to revenue related to the settlement of gas hedges of $6,846,000, $2,609,000 and $17,538,000, oil hedges of $1,529,000, ($192,000) and zero and Ngl hedges of $722,000, zero and zero for the twelve months ended December 31, 2012, 2011 and 2010, respectively.

Comparison of Results of Operations for the Years Ended December 31, 2012 and 2011

Net income (loss) available to common stockholders totaled ($137,218,000) and $5,409,000 for the years ended December 31, 2012 and 2011, respectively. The primary fluctuations were as follows:

Production Total production increased 13% during the year ended December 31, 2012 as compared to the 2011 period. Gas production during the year ended December 31, 2012 increased 12% from the 2011 period. The increase in gas production was primarily the result of the success of our drilling programs in the Woodford Shale in Oklahoma, the Carthage field in East Texas, and the La Cantera field in South Louisiana. Gas production also increased at our West Cameron Block 402 well due to a successful recompletion during the fourth quarter of 2011. Partially offsetting these increases were normal production declines particularly in our Gulf Coast region. As a result of our reduced capital expenditures budget in 2013, we expect our average daily gas production in 2013 to remain stable as compared to 2012.

Oil production during the year ended December 31, 2012 decreased 9% as compared to the 2011 period due primarily to continued normal production declines in our onshore Louisiana and offshore Gulf of Mexico fields. Partially offsetting these decreases were increases from the inception of production from our La Cantera field during March 2012, our Eagle Ford Shale field where five new wells commenced production during the third and fourth quarters of 2012 and at our Mississippian Lime field where initial oil production from our first wells began during the second quarter of 2012 with four additional wells beginning production during the fourth quarter. Additionally, oil production increased at our Ship Shoal field as a result of three successful recompletions performed during the fourth quarter of 2012. As a result of decreased drilling planned for 2013, we expect our average daily oil production to decrease as compared to 2012.

Ngl production during the year ended December 31, 2012 increased 47% from the 2011 period due to the inception of production from our La Cantera field, the liquids rich portion of our Oklahoma properties, and an increase in production at our Carthage field in East Texas. These increases were partially offset by the normal production declines particularly in our Gulf Coast region. As a result of our drilling success in Texas, Oklahoma and the Gulf Coast region, as well as the large allocation of drilling capital in 2013 to the Woodford Shale in Oklahoma, we expect our daily Ngl production in 2013 to increase as compared to 2012.

Prices Including the effects of our hedges, average gas prices per Mcf for the year ended December 31, 2012 were $2.31 as compared to $3.22 for the 2011 period. Average oil prices per Bbl for the year ended December 31, 2012 were $108.79 as compared to $104.99 for the 2011 period and average Ngl prices per Mcfe were $6.32 for the year ended December 31, 2012, as compared to $9.51 for the 2011 period. Stated on an Mcfe basis, unit prices received during the year ended December 31, 2012 were 22% lower than the prices received during the 2011 period.

Revenue Including the effects of hedges, oil and gas sales during the twelve months ended December 31, 2012 decreased 12% to $141,433,000, as compared to oil and gas sales of $160,486,000 during the 2011 period. The decreased revenue during 2012 was primarily the result of lower natural gas and Ngl prices as well as reduced oil production during the period.

Expenses Lease operating expenses for the year ended December 31, 2012 totaled $38,890,000 as compared to $38,571,000 during the 2011 period. Per unit lease operating expenses totaled $1.15 per Mcfe during the twelve month period ended December 31, 2012 as compared to $1.28 during the 2011 period. Per unit lease operating expenses decreased primarily due to the increase in overall produced volumes during the period.

Production taxes for the year ended December 31, 2012 totaled $885,000 as compared to $3,100,000 during the 2011 period. The significant decrease during the 2012 period was the result of recording a receivable of $2,717,000 during June 2012 for refunds relative to severance tax previously paid on our Oklahoma horizontal wells that we expect to receive over the next three years. Beginning in July 2012, we are no longer required to submit the full rate of Oklahoma severance tax on those wells qualifying for the horizontal tax credit. As a result of the refund receivable recorded in 2012, we expect 2013 production taxes to be higher than 2012, and may approximate the taxes incurred in 2011.

General and administrative expenses during the year ended December 31, 2012 totaled $22,957,000 as compared to $20,436,000 during the 2011 period. Included in general and administrative expenses was non-cash share-based compensation expense as follows (in thousands):

	Year Ended December 31, 2012	Year Ended December 31, 2011
Stock options:		
Incentive Stock Options	$ 786	$ 493
Non-Qualified Stock Options	660	703
Restricted stock	5,464	3,637
Share based compensation	$ 6,910	$ 4,833

General and administrative expenses increased 12% during the year ended December 31, 2012 as compared to the comparable period of 2011 primarily due to increased non-cash share-based compensation expense during 2012. We capitalized $11,925,000 of general and administrative costs during the year ended December 31, 2012 as compared to $11,176,000 during the comparable 2011 period. General and administrative expenses in 2013 are expected to approximate 2012 results.

Depreciation, depletion and amortization ("DD&A") expense on oil and gas properties for the year ended December 31, 2012 totaled $59,496,000, or $1.75 per Mcfe, as compared to $57,143,000, or $1.89 per Mcfe, during the comparable 2011 period. The decrease in the per unit DD&A rate is primarily the result of a decrease in the depletable base due to the ceiling test write-downs recognized during 2012.

At December 31, 2012, 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 $2.21 per Mcf of natural gas, $102.81 per barrel of oil, and $6.07 per Mcfe of Ngl. As a result of lower natural gas prices and their negative impact on certain of our longer-lived estimated proved reserves and estimated future net cash flows, we recognized ceiling test write-downs of $137,100,000 during the year ended December 31, 2012. We also recognized a ceiling test write-down of $18,907,000 during the twelve months ended December 31, 2011.

Interest expense, net of amounts capitalized on unevaluated properties, totaled $9,808,000 during the year ended December 31, 2012, as compared to $9,648,000 during 2011. During the year ended December 31, 2012, our capitalized interest totaled $7,036,000 as compared to $7,034,000 during the 2011 period.

Income tax expense (benefit) during the year ended December 31, 2012 totaled $1,636,000, as compared to ($1,810,000) during the 2011 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 $50,866,000 as of December 31, 2012.

Comparison of Results of Operations for the Years Ended December 31, 2011 and 2010

Net income available to common stockholders totaled $5,409,000 and $41,987,000 for the years ended December 31, 2011 and 2010, respectively. The primary reasons for the fluctuations were as follows:

Production Total production decreased 2% during the year ended December 31, 2011 as compared to the 2010 period. However, total production in the fourth quarter of 2011 increased 8% as compared to the third quarter of 2011. Gas production during the year ended December 31, 2011 decreased less than one percent from the comparable period in 2010. The decrease in gas production was primarily the result of normal production declines in the Gulf Coast Basin, offset by increases in gas production from our longer-life basins.

Oil production during the twelve month period ended December 31, 2011 decreased 14% from the comparable 2010 period. The decrease in oil production is primarily the result of normal production declines in the Gulf Coast Basin. Partially offsetting this decrease were increases due to the inception of production in the Niobrara Shale, where our first well began production in the fourth quarter of 2010 and three subsequent wells began production during 2011, and in the Eagle Ford Shale, where our first five wells began production in the third quarter of 2011. These Niobrara and Eagle Ford Shale wells represented 8% of our total oil production during 2011.

Ngl production during the twelve months ended December 31, 2011 decreased 7% from the comparable 2010 period due to the general decline in Gulf Coast gas production.

Prices Including the effects of our hedges, average gas prices per Mcf for the twelve months ended December 31, 2011 were $3.22 as compared to $4.37 for the 2010 period. Average oil prices per Bbl for the twelve months ended December 31, 2011 were $104.99 as compared to $79.47 for the 2010 period. Average Ngl prices per Mcfe for the twelve months ended December 31, 2011 were $9.51 compared to $7.78 during the 2010 period. Stated on an Mcfe basis, unit prices received during the twelve month period ended December 31, 2011 were 8% lower than the prices received during the comparable 2010 period.

Revenue Including the effects of hedges, oil and gas sales during the twelve months ended December 31, 2011 decreased 10% to $160,486,000 as compared to oil and gas sales of $179,038,000 during the 2010 period. The decreased revenue during 2011 was primarily the result of lower gas prices and decreased oil production partially offset by higher oil prices.

Expenses Lease operating expenses for the twelve months ended December 31, 2011 decreased to $38,571,000 as compared to $39,012,000 during the 2010 period. Per unit lease operating expenses totaled $1.28 per Mcfe during the twelve month period ended December 31, 2011 as compared to $1.26 per Mcfe during the 2010 period.

Production taxes decreased during the twelve months ended December 31, 2011 to $3,100,000 from $4,917,000 during the comparable 2010 period. The decrease was primarily the result of refunds received totaling $2,934,000 during 2011 with respect to severance tax previously paid on Oklahoma and East Texas wells as compared to $1,887,000 received during 2010.

General and administrative expenses during the twelve months ended December 31, 2011 totaled $20,436,000 as compared to expenses of $21,341,000 during the 2010 period. Included in general and administrative expenses was share-based compensation expense related to ASC Topic 718, as follows (in thousands):

	Years Ended December 31,	
	2011	2010
Stock options:		
Incentive Stock Options	$ 493	$ 793
Non-Qualified Stock Options	703	2,081
Restricted stock	3,637	4,263
Share-based compensation	$ 4,833	$ 7,137

We capitalized $11,176,000 of general and administrative costs during the twelve month period ended December 31, 2011 and $11,894,000 of such costs during the comparable 2010 period.

Depreciation, depletion and amortization ("DD&A") expense on oil and gas properties for the twelve months ended December 31, 2011 totaled $57,143,000, or $1.89 per Mcfe, as compared to $58,172,000, or $1.88 per Mcfe, during the comparable 2010 period.

As a result of higher estimated future development costs and low natural gas prices and their negative impact on certain of our longer-lived estimated proved reserves and estimated future net cash flows, we recorded non-cash ceiling test write-downs of our oil and gas properties of $18,907,000 during the year ended December 31, 2011. There were no ceiling test write-downs of our oil and gas properties in the 2010 period. See Note 11, "Ceiling Test" for further discussion of the ceiling test write-downs.

Interest expense, net of amounts capitalized on unevaluated properties, totaled $9,648,000 during the twelve months ended December 31, 2011 as compared to $9,952,000 during the 2010 period. We capitalized $7,034,000 of interest during the twelve month period of 2011, and $7,771,000 during the respective 2010 period. The decrease in capitalized interest during the year ended December 31, 2011 was due to the sale of a portion of our unevaluated properties pursuant to the Woodford joint development agreement during the second quarter of 2010. Total interest costs were 6% lower during the twelve months ended December 31, 2011 as compared to the same period in 2010 as a result of the refinancing of our 10 3/8% Senior Notes due 2012 with our 10% Senior Notes due 2017 in August 2010.

In January 2010, we recorded a gain relative to a $9,000,000 cash settlement received from a lawsuit filed by us in 2008 relating to disputed interests in certain oil and gas assets purchased in 2007. In addition to the cash proceeds received, we were assigned additional working interests in certain producing properties. We recorded an additional $4,164,000 gain representing the estimated fair market value of those interests on the effective date of the settlement.

As a result of the early redemption of our 10 3/8% Senior Notes due 2012, we incurred a loss during 2010 totaling $5,973,000. Approximately $1,785,000 of the loss related to non-cash amortization of deferred financing costs and discount associated with the 10 3/8% Senior Notes due 2012.

Income tax expense (benefit) during the twelve months ended December 31, 2011 totaled ($1,810,000) as compared to $1,630,000 during the 2010 period. We 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 prior years, we 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 future reversals of existing deferred tax liabilities. Accordingly, we established a valuation allowance for a portion of the deferred tax asset in prior periods. During 2011, we reversed the remaining valuation allowance as future reversals of existing deferred tax liabilities were sufficient to realize the entire deferred tax asset and we had a net deferred tax liability of $551,000 at December 31, 2011.

Liquidity and Capital Resources

We have financed our acquisition, exploration and development activities to date principally through cash flow from operations, bank borrowings, second lien term credit facilities, issuances of equity and debt securities, joint ventures and sales of assets. At December 31, 2012, we had a working capital deficit of $31.3 million compared to a deficit of $14.0 million at December 31, 2011. The increase in our working capital deficit is primarily the result of our increased operational activities as our capital expenditures during 2012 exceeded our cash flow from operations. Since we operate the majority of our drilling activities, we have the ability to reduce our capital expenditures to manage our working capital deficit and liquidity position. To the extent our capital expenditures in 2013 exceed our cash flow and cash on hand, we plan to utilize available borrowings under the bank credit facility or proceeds from the potential sale of non-core assets to fund a portion of our drilling budget.

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 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.

<u>Source of Capital: Operations</u>

Net cash flow from operations decreased from $119.2 million during the twelve months ended December 31, 2011 to $88.6 million during the 2012 period. The decrease in operating cash flow during 2012 as compared to 2011 was primarily attributable to the decrease in oil and gas revenues during the period due to lower natural gas prices and lower oil production.

<u>Source of Capital: Debt</u>

On August 19, 2010, we issued $150 million in principal amount of 10% Senior Notes due 2017 (the "Notes") in a public offering. At December 31, 2012, the estimated fair value of the Notes was $155.3 million, based upon a market quote provided by an independent broker. The Notes have numerous covenants including restrictions on liens, incurrence of indebtedness, asset sales, dividend payments and other restricted payments. Interest is payable semi-annually on March 1 and September 1. At December 31, 2012, $5.0 million had been accrued in connection with the March 1, 2013 interest payment and we were in compliance with all of the covenants contained in the Notes.

We 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 and Whitney Bank. The Credit Agreement provides us 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 us to use up to $25 million of the borrowing base for letters of credit. The credit facility matures on October 3, 2016. As of December 31, 2012 we had $50 million of borrowings outstanding under (and no letters of credit issued pursuant to) the Credit Agreement.

The borrowing base under the Credit Agreement is based upon the valuation of the reserves attributable to our oil and gas properties as of January 1 and July 1 of each year. The current borrowing base is $130 million (subject to the aggregate commitments of the lenders then in effect). The aggregate commitments of the lenders is currently $100 million and can be increased to up to $300 million by either adding new lenders or increasing the commitments of existing lenders, subject to certain conditions. The next borrowing base redetermination is scheduled to occur by March 31, 2013. We or the lenders may request two additional borrowing base redeterminations 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 our assets, including a lien on all equipment and at least 80% of the aggregate total value of our 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 0.5% to 1.5% depending on total commitments) or the adjusted LIBO rate ("Eurodollar") plus a margin (based on a sliding scale of 1.5% to 2.5% 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 plus 1%. For the purposes of the definition of alternative base rate only, the adjusted LIBO rate is equal to the rate at which dollar deposits of $5,000,000 with a one month maturity are offered by the principal London office of JPMorgan Chase Bank, N.A. in immediately available funds in the London interbank market. 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 us) 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, we pay commitment fees based on a sliding scale of 0.375% to 0.5% depending on total commitments.

We are subject to certain restrictive financial covenants under the Credit Agreement, including a maximum ratio of total debt to EBITDAX, determined on a rolling four quarter basis, of 3.0 to 1.0 and a minimum ratio of consolidated current assets to consolidated current liabilities of 1.0 to 1.0, all as defined in the Credit Agreement. 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. However, the Credit Agreement permits us to repurchase up to $10 million of our common stock during the term of the Credit Agreement, so long as after giving effect to such repurchase our Liquidity (as defined therein) is greater than 20% of the total commitments of the lenders at such time. As of December 31, 2012, we were in compliance with all of the covenants contained in the Credit Agreement.

Source of Capital: Issuance of Securities

During October 2010, our shelf registration statement was declared effective, which allows us to publicly offer and sell up to $250 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: Joint Ventures

In May 2010, we entered into a joint development agreement with WSGP Gas Producing, LLC ("WSGP"), a subsidiary of NextEra Energy Resources, LLC, whereby WSGP acquired approximately 29 Bcfe of our Woodford proved undeveloped reserves as well as the right to earn 50% of our undeveloped Woodford acreage position through a two phase drilling program. We received approximately $57.4 million in cash at closing, net of $2.6 million in transaction fees, and an additional $14 million on November 30, 2011. In addition, since May 2010, WSGP has funded a share of our drilling costs under a drilling program. We achieved certain production performance metrics, as outlined in the joint development agreement, relative to the first 18 wells drilled under the drilling program. As a result, we received an additional $14 million during December 2011.

During February 2012, we amended the joint development agreement with WSGP to provide additional funding for a share of our drilling costs relative to our drilling programs in both our Woodford Shale and Mississippian Lime project areas. WSGP will continue to earn 50% of our undeveloped Woodford Shale acreage as they continue to fund a share of our drilling costs. As of December 31, 2012, approximately $70.7 million of drilling carry remained available.

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 non-strategic assets in order to provide liquidity to strengthen our balance sheet or capital to be reinvested in higher rate of return projects. We are currently exploring divestment opportunities for our Wyoming and South Texas assets. We cannot assure you that we will be able to sell any of our assets in the future.

On December 31, 2012, we sold our non-operated Arkansas assets for a net cash purchase price of $9.2 million. 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.

Use of Capital: Exploration and Development

Our 2013 capital budget, which includes capitalized interest and general and administrative costs, is expected to range between $80 million and $100 million. Because we operate most of our 2013 activities, we expect to be able to manage the timing of our capital expenditures in the event commodity prices or costs do not meet our expectations. We plan to fund our capital expenditures with cash flow from operations and cash on hand. To the extent our capital expenditures during 2013 exceed these sources, we plan to utilize available borrowings under the bank credit facility or proceeds from the potential sale of non-core assets. To the extent additional capital is required, we may utilize sales of equity or debt securities or we may reduce our capital expenditures to manage our liquidity position.

Use of Capital: Acquisitions

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

We expect to finance our future acquisition activities, if consummated, through cash on hand 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, 2012 (in thousands):

	Total	2013	2014	2015	2016	2017	After 2017
10% Senior Notes (1)	$ 220,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 160,000	$ —
Bank debt (1)	54,865	1,120	1,245	1,370	51,130	—	—
Operating leases (2)	5,155	1,211	1,032	1,026	988	898	—
Asset retirement obligations (3)	27,259	2,351	3,825	975	932	—	19,176
Purchase commitments (4)	5,784	5,784	—	—	—	—	—
Total	$ 313,063	$ 25,466	$ 21,102	$ 18,371	$ 68,050	$ 160,898	$ 19,176

(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 certain drilling rig contracts.

Item 7A Quantitative and Qualitative Disclosure 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 and natural gas production. Based on projected annual sales volumes for 2013, a 10% decline in the estimated average prices we expect to receive for our crude oil and natural gas production would have an approximate $14.5 million impact on our 2013 revenues.

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 2012, we received approximately $9.1 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 Wells Fargo Bank, 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, 2012, we had entered into the following gas hedge contracts:

Production Period	Instrument Type	Daily Volumes	Weighted Average Price
Natural Gas:			
2013	3-way collar	10,000 Mmbtu	$2.00-$3.00-$4.09
2013	Swap	5,000 Mmbtu	$4.00

At December 31, 2012, we recognized a net asset of approximately $0.6 million related to the estimated fair value of these derivative instruments. Based on estimated future commodity prices as of December 31, 2012, we would realize a $0.4 million gain, net of taxes, as an increase to oil and gas sales during the next 12 months. This gain is expected to be reclassified based on the schedule of gas volumes stipulated in the derivative contracts.

During January and February 2013, we entered into the following additional hedge contracts accounted for as cash flow hedges:

Production Period	Instrument Type	Daily Volumes	Weighted Average Price
Crude Oil:			
February - December 2013	Swap	250 Bbls	$104.75
Natural Gas:			
February - December 2013	Swap	10,000 Mmbtu	$3.71
March - December 2013	Swap	5,000 Mmbtu	$3.50
April - December 2013	Swap	5,000 Mmbtu	$3.74
January - December 2014	Swap	10,000 Mmbtu	$4.08

After executing the above transactions, the Company has approximately 11.7 Bcf of gas volumes, at an average price of $3.51 per Mcf, and approximately 84,000 barrels of oil volumes at $104.75 per barrel, hedged for 2013 and 3.7 Bcf of gas volumes at an average price of $4.08 per Mcf hedged in 2014.

Debt outstanding under our bank credit facility is subject to a floating interest rate and represents 25% of our total debt as of December 31, 2012. Based upon an analysis, utilizing the actual interest rate in effect and balances outstanding as of December 31, 2012, and assuming a 10% increase in interest rates and no changes in the amount of debt outstanding, the potential effect on interest expense for 2013 is $0.1 million.

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 Securities and Exchange Act of 1934, as amended (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, 2012 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, 2012. 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, 2012 based upon criteria in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our assessment, management believes that our internal control over financial reporting was effective as of December 31, 2012 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, 2012.

March 11, 2013

/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, 2012, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (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, 2012, 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, 2012 and 2011, and the related consolidated statements of operations, comprehensive income, cash flows, and stockholders' equity for each of the three years in the period ended December 31, 2012 and our report dated March 11, 2013 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

New Orleans, Louisiana
March 11, 2013

Item 9B. **Other Information**

NONE

PART III

Item 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 21, 2013, 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, 2012 and 2011
Consolidated Statements of Operations for the three years ended December 31, 2012
Consolidated Statements of Comprehensive Income for the three years ended December 31, 2012
Consolidated Statements of Cash Flows for the three years ended December 31, 2012
Consolidated Statements of Stockholders' Equity for the three years ended December 31, 2012
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).

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 December 20, 2007 (incorporated herein by reference to Exhibit 3.1 to Form 8-K filed December 21, 2007).

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 May 11, 2005, among PetroQuest Energy, Inc., PetroQuest Energy, LLC, the Subsidiary Guarantors identified therein, and the Bank of New York Trust Company, N.A. (incorporated herein by reference to Exhibit 4.1 to Form 8-K filed May 11, 2005).
4.4	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 4.1 to Form 8-K filed on August 19, 2010).
4.5	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).
4.6	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).
†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, W. Todd Zehnder, Arthur M. Mixon, III, Daniel G. Fournerat, Mark K. Stover, J. Bond Clement, and Tracy Price) under the 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 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, W. Todd Zehnder, Arthur M. Mixon, III, Daniel G. Fournerat, Mark K. Stover, J. Bond Clement, and Tracy Price) under the 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	Form of Award Notice of Restricted Stock Units - Employees (including Charles T. Goodson, W. Todd Zehnder, Arthur M. Mixon, III, Daniel G. Fournerat, Mark K. Stover, J. Bond Clement and Tracy Price) (incorporated herein by reference to Exhibit 10.2 to Form 8-K filed November 15, 2012).
10.10	Form of Award Notice of Restricted Stock Units - Outside Director/Consultant (incorporated herein by reference to Exhibit 10.3 to Form 8-K filed November 15, 2012).
10.11	Form of Restricted Stock Agreement - Executive Officers (including Charles T. Goodson, W. Todd Zehnder, Arthur M. Mixon, III, Daniel G. Fournerat, Mark K. Stover, J. Bond Clement and Tracy Price) (incorporated herein by reference to Exhibit 10.4 to Form 8-K filed November 15, 2012).
10.12	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).

10.13	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).
10.14	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).
10.15	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).
10.16	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).
†10.17	Amended Executive Employment Agreement dated effective as of December 31, 2008, between Charles T. Goodson and PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed January 6, 2009).
†10.18	Amended Executive Employment Agreement dated effective as of December 31, 2008, between W. Todd Zehnder and PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit 10.2 to Form 8-K filed January 6, 2009).
†10.19	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).
†10.20	Amended Executive Employment Agreement dated effective as of December 31, 2008, between Daniel G. Fournerat and PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit 10.4 to Form 8-K filed January 6, 2009).
†10.21	Amended Executive Employment Agreement dated effective as of December 31, 2008, between Mark K. Stover and PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit 10.19 to Form 10-K filed February 27, 2009).
†10.22	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).
†10.23	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).
†10.24	Form of Amended Termination Agreement between the Company and each of its executive officers, including Charles T. Goodson, W. Todd Zehnder, Arthur M. Mixon, III, Daniel G. Fournerat, Mark K. Stover, and J. Bond Clement (incorporated herein by reference to Exhibit 10.6 to Form 8-K filed January 6, 2009).
†10.25	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).
†10.26	Form of Indemnification Agreement between PetroQuest Energy, Inc. and each of its directors and executive officers, including Charles T. Goodson, W. Todd Zehnder, Arthur M. Mixon, III, Daniel G. Fournerat, Mark K. Stover, J. Bond Clement, Tracy Price, 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).

10.27	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).
10.28	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).
10.29	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).
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, 2012, 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.

† Management contract or compensatory plan or arrangement

(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 11, 2013.

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 11, 2013.

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, 2012 and 2011, and the related consolidated statements of operations, comprehensive income, cash flows and stockholders' equity for each of the three years in the period ended December 31, 2012. 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, 2012 and 2011, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, 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, 2012, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 11, 2013 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

New Orleans, Louisiana
March 11, 2013

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

	December 31, 2012	December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	$ 14,904	$ 22,263
Revenue receivable	17,742	15,860
Joint interest billing receivable	42,595	47,445
Other receivable	9,208	—
Derivative asset	830	6,418
Prepaid drilling costs	1,698	2,900
Drilling pipe inventory	707	4,070
Other current assets	1,900	2,965
Total current assets	89,584	101,921
Property and equipment:		
Oil and gas properties:		
Oil and gas properties, full cost method	1,734,477	1,600,546
Unevaluated oil and gas properties	71,713	70,408
Accumulated depreciation, depletion and amortization	(1,472,244)	(1,265,603)
Oil and gas properties, net	333,946	405,351
Other property and equipment	12,370	10,627
Accumulated depreciation of other property and equipment	(7,607)	(6,414)
Total property and equipment	338,709	409,564
Other assets, net of accumulated amortization of $4,240 and $3,446, respectively	5,110	4,681
Total assets	$ 433,403	$ 516,166
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable to vendors	$ 58,960	$ 50,750
Advances from co-owners	20,459	33,867
Oil and gas revenue payable	26,175	13,764
Accrued interest and preferred stock dividend	6,190	6,167
Asset retirement obligation	2,351	3,110
Derivative liability	233	—
Other accrued liabilities	6,535	8,250
Total current liabilities	120,903	115,908
Bank debt	50,000	—
10% Senior Notes	150,000	150,000
Asset retirement obligation	24,909	27,317
Deferred income taxes	—	551
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 62,768 and 62,148 shares, respectively	63	62
Paid-in capital	276,534	270,606
Accumulated other comprehensive income	521	4,031
Accumulated deficit	(189,528)	(52,310)
Total stockholders' equity	87,591	222,390
Total liabilities and stockholders' equity	$ 433,403	$ 516,166

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, 2012	2011	2010
Revenues:			
Oil and gas sales	$ 141,433	$ 160,486	$ 179,038
Gas gathering revenue	158	214	225
	141,591	160,700	179,263
Expenses:			
Lease operating expenses	38,890	38,571	39,012
Production taxes	885	3,100	4,917
Depreciation, depletion and amortization	60,689	58,243	59,326
Ceiling test write-down	137,100	18,907	—
General and administrative	22,957	20,436	21,341
Accretion of asset retirement obligation	2,078	2,049	1,306
Interest expense	9,808	9,648	9,952
	272,407	150,954	135,854
Other income (expense):			
Gain on legal settlement	—	—	12,400
Loss on early extinguishment of debt	—	—	(5,973)
Other income (expense)	606	(1,008)	(1,080)
Derivative income (expense)	(233)	—	—
	373	(1,008)	5,347
Income (loss) from operations	(130,443)	8,738	48,756
Income tax expense (benefit)	1,636	(1,810)	1,630
Net income (loss)	(132,079)	10,548	47,126
Preferred stock dividend	5,139	5,139	5,139
Net income (loss) available to common stockholders	$ (137,218)	$ 5,409	$ 41,987
Earnings per common share:			
Basic			
Net income (loss) per share	$ (2.20)	$ 0.08	$ 0.67
Diluted			
Net income (loss) per share	$ (2.20)	$ 0.08	$ 0.66
Weighted average number of common shares:			
Basic	62,459	61,937	61,415
Diluted	62,459	62,325	61,789

See accompanying Notes to Consolidated Financial Statements.

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

	Year Ended December 31, 2012	2011	2010
Net income (loss)	$ (132,079)	$ 10,548	$ 47,126
Change in fair value of derivatives, net of income tax (expense) benefit of $2,079, ($2,388), and $1,028, respectively	(3,510)	5,120	(2,857)
Comprehensive income (loss)	$ (135,589)	$ 15,668	$ 44,269

See accompanying Notes to Consolidated Financial Statements.

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

	Year Ended December 31, 2012	2011	2010
Cash flows from operating activities:			
Net income (loss)	$ (132,079)	$ 10,548	$ 47,126
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Deferred tax expense (benefit)	1,636	(1,810)	1,630
Depreciation, depletion and amortization	60,689	58,243	59,326
Ceiling test write-down	137,100	18,907	—
Non-cash gain on legal settlement	—	—	(4,164)
Loss on early extinguishment of debt	—	—	5,973
Accretion of asset retirement obligation	2,078	2,049	1,306
Share based compensation expense	6,910	4,833	7,137
Amortization costs and other	881	625	1,334
Non-cash derivative expense	233	—	—
Payments to settle asset retirement obligations	(2,627)	(905)	(6,274)
Changes in working capital accounts:			
Revenue receivable	(1,882)	(2,474)	3,071
Prepaid drilling and pipe costs	4,479	5,530	9,180
Joint interest billing and other receivable	3,981	(35,252)	(401)
Accounts payable and accrued liabilities	20,916	34,599	3,368
Advances from co-owners	(13,408)	25,904	4,301
Other	(316)	(1,621)	(227)
Net cash provided by operating activities	88,591	119,176	132,686
Cash flows used in investing activities:			
Investment in oil and gas properties	(147,771)	(194,536)	(103,926)
Investment in other property and equipment	(1,743)	(1,286)	(1,042)
Sale of oil and gas properties	837	14,000	35,000
Sale of unevaluated oil and gas properties	8,889	28,461	22,473
Net cash used in investing activities	(139,788)	(153,361)	(47,495)
Cash flows used in financing activities:			
Net payments for share based compensation	(981)	(1,133)	(210)
Deferred financing costs	(42)	(517)	(12)
Payment of preferred stock dividend	(5,139)	(5,139)	(5,137)
Proceeds from bank borrowings	102,500	22,000	—
Repayment of bank borrowings	(52,500)	(22,000)	(29,000)
Redemption of 10 3/8% Senior Notes	—	—	(150,000)
Costs to redeem 10 3/8% Senior Notes	—	—	(4,187)
Proceeds from issuance of 10% Senior Notes	—	—	150,000
Costs to issue 10% Senior Notes	—	—	(4,180)
Net cash provided by (used in) financing activities	43,838	(6,789)	(42,726)
Net increase (decrease) in cash and cash equivalents	(7,359)	(40,974)	42,465
Cash and cash equivalents, beginning of period	22,263	63,237	20,772
Cash and cash equivalents, end of period	$ 14,904	$ 22,263	$ 63,237
Supplemental disclosure of cash flow information:			
Cash paid during the period for:			
Interest	$ 16,026	$ 16,017	$ 11,195
Income taxes	$ 105	$ 51	$ 192

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, 2009	$ 61	$ 1	$ 259,981	$ 1,768	$ (99,706)	$ 162,105
Options exercised	1	—	296	—	—	297
Retirement of shares upon vesting of restricted stock	—	—	(507)	—	—	(507)
Share-based compensation expense	—	—	7,137	—	—	7,137
Derivative fair value adjustment, net of tax	—	—	—	(2,857)	—	(2,857)
Preferred stock dividend	—	—	—	—	(5,139)	(5,139)
Net income	—	—	—	—	47,126	47,126
December 31, 2010	$ 62	$ 1	$ 266,907	$ (1,089)	$ (57,719)	$ 208,162
Options exercised	—	—	234	—	—	234
Retirement of shares upon vesting of restricted stock	—	—	(1,368)	—	—	(1,368)
Share-based compensation expense	—	—	4,833	—	—	4,833
Derivative fair value adjustment, net of tax	—	—	—	5,120	—	5,120
Preferred stock dividend	—	—	—	—	(5,139)	(5,139)
Net income	—	—	—	—	10,548	10,548
December 31, 2011	$ 62	$ 1	$ 270,606	$ 4,031	$ (52,310)	$ 222,390
Options exercised	—	—	260	—	—	260
Retirement of shares upon vesting of restricted stock	1	—	(1,242)	—	—	(1,241)
Share-based compensation expense	—	—	6,910	—	—	6,910
Derivative fair value adjustment, net of tax	—	—	—	(3,510)	—	(3,510)
Preferred stock dividend	—	—	—	—	(5,139)	(5,139)
Net loss	—	—	—	—	(132,079)	(132,079)
December 31, 2012	$ 63	$ 1	$ 276,534	$ 521	$ (189,528)	$ 87,591

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 Houston, Texas and Tulsa, Oklahoma. It is engaged in the exploration, development, acquisition and operation of oil and gas properties in Oklahoma, Wyoming and Texas as well as onshore and in the shallow waters offshore the Gulf Coast Basin.

Principles of Consolidation

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

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

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, unless significant, are recorded as adjustments to accumulated depreciation, depletion and amortization with no gain or loss recognized.

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 should be 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. As of December 31, 2012 and 2011, the Company had \$0.1 million and \$1.0 million, respectively, recorded related to an allowance for doubtful accounts. At December 31, 2012, \$9.2 million was recorded as an other receivable relative to net proceeds from the sale of the Company's non-operated Arkansas assets, which were collected in January 2013.

Other Property and Equipment

During 2006, the Company acquired an interest in a gas gathering system used in the transportation of natural gas. The costs related to this system are depreciated on a straight line basis over the estimated remaining useful life, generally 14 years. During 2012, the Company acquired well service equipment to be used on its oil and gas related activities. The costs related to these assets and other furniture and fixtures are depreciated on a straight line basis over estimated useful lives ranging from 3-8 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 includes deferred financing costs, which are amortized over the life of the related debt, and the long-term portion of a severance tax receivable from the state of Oklahoma, which is payable over the next 2.5 years.

Drilling Pipe Inventory

Drilling pipe inventory, which is included in current assets, consists of tubular goods and pipe that the Company either utilizes in its ongoing exploration and development activities or has available for sale. The cost basis of drilling pipe inventory to be utilized is depreciated as a component of oil and gas properties once the inventory is used in drilling or other capitalized operations.

Other Accrued Liabilities

Other accrued liabilities at December 31, 2012 and 2011 included \$5.7 million and \$7.0 million, respectively, related to accrued incentive compensation costs.

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. Gas balancing obligations as of December 31, 2012 and 2011 were not significant.

Certain 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 net 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,		
	2012	**2011**	**2010**
Shell Trading Co.	30%	18%	19%
Laclede Energy	17%	20%	17%
JP Morgan Ventures Energy	12%	(a)	(a)
Texon LP	(a)	15%	17%
Gary Williams	(a)	11%	10%

(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 cash settlements and changes in the fair value of the derivative are recorded in the income statement as derivative income (expense). The Company does not offset fair value amounts recognized for derivative instruments. The cash settlements of effective hedges are recorded as adjustments to oil and gas sales. Oil and gas revenues include additions related to the net settlement of hedges totaling $9.1 million, $2.4 million and $17.5 million during 2012, 2011 and 2010, 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, 2012, the Company's derivative instruments, with the exception of a three-way collar contract for 2013 natural gas production, were designated effective cash flow hedges. See Note 7 for further discussion of the Company's derivative instruments.

Note 2—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.

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 3—Woodford Joint Development Agreement

In May 2010, PetroQuest Energy, L.L.C. entered into a joint development agreement ("JDA") with WSGP Gas Producing LLC (WSGP), a subsidiary of NextEra Energy Resources, LLC, whereby WSGP acquired approximately 29 Bcfe of the Company's Woodford proved undeveloped reserves (PUDs) as well as the right to earn 50% of the Company's undeveloped Woodford acreage position through a two phase drilling program. The Company received $57.4 million in cash at closing, net of $2.6 million in fees incurred in relation to the transaction, and recorded a $14.0 million receivable for a contractual payment that was to be received in 2011. The Company received the $14.0 million contractual payment on November 30, 2011. The Company recorded the total consideration of approximately $71.0 million during 2010 as an adjustment to capitalized costs with no gain or loss recognized. Certain defined production performance metrics were achieved during the fourth quarter of 2011 and the Company received an additional $14 million during December 2011, which was also recorded as a reduction of capitalized costs. Additionally, since May 2010, WSGP has funded a share of the Company's drilling costs under a long-term drilling program.

During February 2012, the Company amended its Woodford Shale JDA to accelerate the entry into Phase 2 of the drilling program and modify the drilling carry ratio effective March 1, 2012. Under the amended JDA, the Phase 2 drilling carry has been expanded to provide for development in both the Mississippian Lime and Woodford Shale plays whereby the Company will pay 25% of the cost to drill and complete wells and receive a 50% ownership interest. The Phase 2 drilling carry totals approximately $93 million and will be subject to extensions in one-year intervals.

Note 4—Earnings Per Share

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

For the Year Ended December 31, 2012	Loss (Numerator)	Shares (Denominator)	Per Share Amount
BASIC EPS			
Net loss available to common stockholders	$ (137,218)	62,459	$ (2.20)
Effect of dilutive securities:			
Stock options	—	—	
Restricted stock	—	—	
DILUTED EPS	$ (137,218)	62,459	$ (2.20)

For the Year Ended December 31, 2011	Income (Numerator)	Shares (Denominator)	Per Share Amount
Net income available to common stockholders	$ 5,409	61,937	
Attributable to participating securities	(154)	—	
BASIC EPS	$ 5,255	61,937	$ 0.08
Net income available to common stockholders	$ 5,409	61,937	
Effect of dilutive securities:			
Stock options	—	388	
Attributable to participating securities	(153)	—	
DILUTED EPS	$ 5,256	62,325	$ 0.08

For the Year Ended December 31, 2010	Income (Numerator)	Shares (Denominator)	Per Share Amount
Net income available to common stockholders	$ 41,987	61,415	
Attributable to participating securities	(1,029)	—	
BASIC EPS	$ 40,958	61,415	$ 0.67
Net income available to common stockholders	$ 41,987	61,415	
Effect of dilutive securities:			
Stock options	—	374	
Attributable to participating securities	(1,023)	—	
DILUTED EPS	$ 40,964	61,789	$ 0.66

An aggregate of 0.9 million shares of common stock representing options to purchase common stock and unvested shares of restricted common stock and common shares issuable upon the assumed conversion of the Series B preferred stock totaling 5.1 million shares were not included in the computation of diluted earnings per share for the year ended December 31, 2012, because the inclusion would have been anti-dilutive as a result of the net loss reported for the period.

Common shares issuable upon the assumed conversion of the Series B preferred stock totaling 5.1 million shares during 2011 and 2010 were not included in the computation of diluted earnings per share because the inclusion would have been anti-dilutive. Options to purchase 1.1 million, 0.1 million and 1.7 million shares of common stock were outstanding during the year ended December 31, 2012, 2011 and 2010, 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 5—Share-Based Compensation

Share-based compensation expense is reflected as a component of the Company's general and administrative expense. A detail of share-based compensation expense for the periods ended December 31, 2012, 2011 and 2010 is as follows (in thousands):

	Year Ended December 31,		
	2012	2011	2010
Stock options:			
Incentive Stock Options	$ 786	$ 493	$ 793
Non-Qualified Stock Options	660	703	2,081
Restricted stock	5,464	3,637	4,263
Restricted stock units	277	—	—
Share based compensation	$ 7,187	$ 4,833	$ 7,137

During the years ended December 31, 2012, 2011 and 2010, the Company recorded income tax benefits of approximately \$2.3 million, \$1.6 million and \$2.4 million, respectively, related to share-based compensation expense recognized during those periods. Share-based compensation expense for the year ended December 31, 2010 included a charge of approximately \$0.5 million related to the voluntary early cancellation of certain stock options and accelerated recognition of associated compensation expense. 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.

At December 31, 2012, the Company had \$6.7 million of unrecognized compensation cost related to granted restricted stock and stock options. This amount will be recognized as compensation expense over a weighted average period of approximately two years.

<u>*Stock Options*</u>

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. The Company recognizes compensation expense using the accelerated expense attribution method over the vesting period. Periodically, the Company adjusts compensation expense based on the difference between actual and estimated forfeitures.

The following table outlines the assumptions used in computing the fair value of stock options granted during 2012, 2011 and 2010:

	Years Ended December 31,		
	2012	**2011**	**2010**
Dividend yield	—%	—%	—%
Expected volatility	79.2% - 79.6%	78.5% - 79.7%	78.2% - 80.3%
Risk-free rate	0.8% - 1.1%	1.1% - 2.2%	1.5% - 3.0%
Expected term	6 years	6 years	6 years
Forfeiture rate	5.0%	5.0%	5.0%
Stock options granted (1)	125,487	395,280	69,500
Wgtd. avg. grant date fair value per share	$ 3.71	$ 5.09	$ 4.21
Fair value of grants (1)	$ 465,000	$ 2,011,000	$ 293,000

(1) Prior to applying estimated forfeiture rate

The following table details stock option activity during the year ended December 31, 2012:

	Number of Options	Wgtd. Avg. Exercise Price	Wgtd. Avg. Remaining Life	Aggregate Intrinsic Value (000's)
Outstanding at beginning of year	1,922,408	$ 5.56		
Granted	125,487	5.51		
Expired/cancelled/forfeited	(44,554)	6.71		
Exercised	(78,400)	3.32		
Outstanding at end of year	1,924,941	5.61	5.0 years	$ 1,114
Options exercisable at end of year	1,534,311	$ 5.31	4.1 years	$ 1,114
Options expected to vest	371,098	6.79	8.8 years	$ 48

The total fair value of stock options that vested during the years ended December 31, 2012, 2011 and 2010 was $1.7 million, $1.1 million and $3.6 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, 2012:

Range of Exercise Price	Options Outstanding 12/31/2012	Wgtd. Avg. Remaining Contractual Life	Wgtd. Avg. Exercise Price	Options Exercisable 12/31/2012	Wgtd. Avg. Exercise Price
$0.0—$3.17	450,667	1.0 years	$2.92	450,667	$2.92
$3.17—$5.91	422,818	4.1 years	$4.53	308,831	$4.23
$5.91—$7.08	672,862	6.4 years	$6.98	639,195	$7.01
$7.08—$9.99	378,594	8.4 years	$7.59	135,618	$7.71
	1,924,941	5.0 years	$5.61	1,534,311	$5.31

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. Restricted stock granted to directors generally vests evenly over a three year period. Beginning January 1, 2011, restricted stock granted to employees generally vests evenly over a three year period. Upon a change in control of the Company, all outstanding shares of restricted stock will become immediately vested. Compensation expense related to restricted stock is recognized over the vesting period using the accelerated expense attribution method.

The following table details restricted stock activity during 2012:

	Number of Shares	Wgtd. Avg. Fair Value per Share
Outstanding at beginning of year	1,988,602	$ 6.69
Granted	659,915	5.24
Expired/cancelled/forfeited	(109,236)	6.64
Lapse of restrictions	(733,452)	6.40
Outstanding at December 31, 2012	1,805,829	$ 6.28

The weighted average grant date fair value of restricted stock granted during the years ended December 31, 2012, 2011 and 2010 was $5.24, $7.54 and $5.44, respectively, per share. The total fair value of restricted stock that vested during the years ended December 31, 2012, 2011 and 2010 was $4.7 million, $5.6 million and $2.6 million, respectively. At December 31, 2012, the weighted average remaining life of restricted stock outstanding was two years and the intrinsic value of restricted stock outstanding, using the closing stock price on December 31, 2012, was $8.9 million.

Restricted Stock Units

The Company granted restricted stock units ("RSUs") to employees during 2012. The RSUs vest in one-third increments on each of the first, second and third anniversaries of the date of grant. 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 become immediately vested. Compensation expense is recognized on a straight line basis over the vesting period assuming a 5% estimated forfeiture rate. The Company computes the fair value of the RSUs using the closing price of the Company's stock for purposes of determining the amount of the liability at the end of each period. As of December 31, 2012, the Company had 1.1 million RSUs outstanding with an aggregate fair value of $5.2 million. There were no cash payments made to settle RSUs during 2012 and no RSUs were vested as of December 31, 2012.

Note 6—Asset Retirement Obligation

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

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

	Year Ended December 31,	
	2012	2011
Asset retirement obligation, beginning of period	$ 30,427	$ 24,592
Liabilities incurred	892	220
Liabilities settled	(2,627)	(905)
Accretion expense	2,078	2,049
Revisions in estimated cash flows	(3,510)	4,471
Asset retirement obligation, end of period	27,260	30,427
Less: current portion of asset retirement obligation	(2,351)	(3,110)
Long-term asset retirement obligation	$ 24,909	$ 27,317

Liabilities settled during 2012 included two offshore fields and one onshore field that were decommissioned. Additionally, the liabilities for three onshore fields were settled due to the sale of the fields. Revisions during 2012 primarily represent revised timing of plugging and abandonment operations. Revisions during 2011 primarily represent increased cost estimates to decommission the Company's offshore fields including platforms, pipelines and the related wells.

Note 7—Derivative Instruments

The Company seeks to reduce its exposure to commodity price volatility by hedging a portion of its production through commodity derivative instruments. When the conditions for hedge accounting are met, the Company may designate its commodity derivatives as cash flow hedges.

Oil and gas sales include additions (reductions) related to the settlement of gas hedges of $6,846,000, $2,609,000 and $17,538,000, Ngl hedges of $722,000, zero and zero, and oil hedges of $1,529,000, ($192,000) and zero, for the years ended December 31, 2012, 2011 and 2010, respectively.

As of December 31, 2012, the Company had entered into the following gas hedge contracts:

Production Period	Instrument Type	Daily Volumes	Weighted Average Price
Natural Gas:			
2013	3-way collar	10,000 Mmbtu	$2.00-$3.00-$4.09
2013	Swap	5,000 Mmbtu	$4.00

At December 31, 2012, the Company had recognized a net asset of approximately $0.6 million related to the estimated fair value of these derivative instruments. Based on estimated future commodity prices as of December 31, 2012, the Company would realize a $0.4 million gain, net of taxes, during the next 12 months. These gains are expected to be reclassified to oil and gas sales based on the schedule of gas volumes stipulated in the derivative contracts.

During January and February 2013, we entered into the following additional hedge contracts accounted for as cash flow hedges:

Production Period	Instrument Type	Daily Volumes	Weighted Average Price
Crude Oil:			
February - December 2013	Swap	250 Bbls	$104.75
Natural Gas:			
February - December 2013	Swap	10,000 Mmbtu	$3.71
March - December 2013	Swap	5,000 Mmbtu	$3.50
April - December 2013	Swap	5,000 Mmbtu	$3.74
January - December 2014	Swap	10,000 Mmbtu	$4.08

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, 2012 and December 31, 2011:

	Commodity Derivatives		
Period	Balance Sheet Location		Fair Value
December 31, 2012	Derivative asset	$	830
December 31, 2011	Derivative asset	$	6,418

Effect of Cash Flow Hedges on the Consolidated Statement of Operations for the years ended December 31, 2012, 2011 and 2010:

Instrument		Amount of Gain (Loss) Recognized in Other Comprehensive Income	Location of Gain Reclassified into Income		Amount of Gain Reclassified into Income
Commodity Derivatives at December 31, 2012	$	(3,510)	Oil and gas sales	$	9,097
Commodity Derivatives at December 31, 2011	$	5,120	Oil and gas sales	$	2,417
Commodity Derivatives at December 31, 2010	$	(2,857)	Oil and gas sales	$	17,538

Derivatives not designated as hedging instruments:

The Company's three-way collar contract for 2013 gas production has not been designated as an effective cash flow hedge and therefore both realized and unrealized (mark-to-market) gains or losses on this derivative are recorded as derivative expense (income) on the statement of operations. The following tables reflect the fair value of this contract in the consolidated financial statements (in thousands):

Effect of Non-designated Derivative Instrument on the Consolidated Balance Sheet at December 31, 2012 and December 31, 2011:

	Commodity Derivatives		
Period	Balance Sheet Location		Fair Value
December 31, 2012	Derivative liability	$	(233)
December 31, 2011		$	—

Effect of Non-designated Derivative Instrument on the Consolidated Statement of Operations for the twelve months ended December 31, 2012, 2011 and 2010:

Instrument	Amount of Unrealized Loss Recognized in Derivative Expense	
Commodity Derivatives at December 31, 2012	$	(233)
Commodity Derivatives at December 31, 2011	$	—
Commodity Derivatives at December 31, 2010	$	—

Note 8 - Fair Value Measurements

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

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

The Company's commodity derivatives are required to be measured at fair value on a recurring basis. 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, 2012 and December 31, 2011 (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, 2012	$	—	$	597	$	—
At December 31, 2011	$	—	$	6,418	$	—

The fair value of the Company's cash and cash equivalents and variable-rate bank debt approximated book value at December 31, 2012 and 2011. As of December 31, 2012 and 2011, the fair value of the Company's $150 million 10% Senior Notes due 2017 (the "Notes") was approximately $155.3 million and $151.5 million, 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 9—Long-Term Debt

On August 19, 2010, PetroQuest issued $150 million in principal amount of the Notes in a public offering. The Notes are guaranteed by certain of PetroQuest's subsidiaries. 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 ("SEC"). The Notes have numerous covenants including restrictions on liens, incurrence of indebtedness, asset sales, dividend payments and other restricted payments. Interest is payable semi-annually on March 1 and September 1. At December 31, 2012, $5.0 million had been accrued in connection with the March 1, 2013 interest payment 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 and Whitney Bank. 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 October 3, 2016. As of December 31, 2012, the Company had $50.0 million of borrowings outstanding under (and no letters of credit issued pursuant to) the Credit Agreement.

The borrowing base under the Credit Agreement is 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. In connection with the most recent redetermination, the borrowing base was increased from $125 million to $130 million (subject to the aggregate commitments of the lenders then in effect) effective September 28, 2012. The aggregate commitments of the lenders is currently $100 million and can be increased to up to $300 million by either adding new lenders or increasing the commitments of existing lenders, subject to certain conditions. The next borrowing base redetermination is scheduled to occur by March 31, 2013. The Company or the lenders may request two additional borrowing base redeterminations 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 80% of the aggregate total value of the Company'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 0.5% to 1.5% depending on total commitments) or the adjusted LIBO rate ("Eurodollar") plus a margin (based on a sliding scale of 1.5% to 2.5% 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 plus 1%. For the purposes of the definition of alternative base rate only, the adjusted LIBO rate is equal to the rate at which dollar deposits of $5,000,000 with a one month maturity are offered by the principal London office of JPMorgan Chase Bank, N.A. in immediately available funds in the London interbank market. 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 a maximum ratio of total debt to EBITDAX, determined on a rolling four quarter basis, of 3.0 to 1.0, and a minimum ratio of consolidated current assets to consolidated current liabilities of 1.0 to 1.0, all as defined in the Credit Agreement. 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. However, the Credit Agreement permits the Company to repurchase up to $10 million of the Company's common stock during the term of the Credit Agreement, as long as after giving effect to such repurchase the Borrower's Liquidity (as defined therein) is greater than 20% of the total commitments of the lenders at such time. As of December 31, 2012, the Company was in compliance with all of the covenants contained in the Credit Agreement.

Note 10—Related Party Transactions

Three of the Company's senior officers, Charles T. Goodson, Stephen H. Green, and Mark K. Stover, 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 2012, in their capacities as working interest owners or overriding royalty interest owners, revenues, net of costs, were disbursed to Messrs. Goodson, Green, Stover, Nordberg, or their affiliates, in the amounts of $104,000, $387,000, $112,000 and $100, respectively. During 2011, in their capacities as working interest owners or overriding royalty interest owners, revenues, net of costs, were disbursed to Messrs. Goodson, Green, Stover, or their affiliates, in the amounts of $293,000, $546,000 and $328,000, respectively, and with respect to Mr. Nordberg, costs billed exceeded revenues disbursed in the amount of $9. During 2010, in their capacities as working interest owners or overriding royalty interest owners, revenues, net of costs, were disbursed to Messrs. Goodson, Green and Stover, or their affiliates, in the amounts of $103,000, $520,000 and $261,000, respectively, and with respect to Mr. Nordberg, costs in the amount of $100 were billed with no revenue disbursed. No such disbursements were made to Mr. Rucks during 2012, 2011 and 2010. 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 in 2012 and 2011.

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, 2012, the Company's joint interest billing receivable included approximately $5,000 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, 2012.

Periodically, the Company charters private aircraft for business purposes. During 2012, 2011 and 2010, the Company paid approximately $16,900, $128,200 and $169,400, respectively, 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. The Company's use of flight hours purchased by Mr. Goodson was pre-approved by the Company's Audit Committee and there is no agreement or obligation by or on behalf of the Company to utilize this aircraft arrangement.

Note 11—Ceiling Test Write-downs

As a result of lower natural gas prices and their negative impact on certain of the Company's longer-lived estimated proved reserves and estimated future net cash flows, the Company recognized ceiling test write-downs of $137.1 million and $18.9 million during 2012 and 2011, respectively. No such write-down occurred during 2010. At December 31, 2012, 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 $2.21 per Mcf of natural gas, $102.81 per barrel of oil and $6.07 per Mcfe of Ngl. The Company's cash flow hedges in place decreased the ceiling test write-down by approximately $2.2 million and $3.9 million during 2012 and 2011, respectively.

Note 12—Investment in Oil and Gas Properties

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,		
	2012	2011	2010
Acquisition costs:			
Proved	$ 352	$ 2,720	$ 10,421
Unproved	15,677	43,207	11,310
Divestitures—unproved (1)	(8,889)	(14,461)	(36,139)
Exploration costs:			
Proved	72,361	92,466	34,310
Unproved	18,033	5,919	10,384
Development costs	18,740	34,400	34,286
Capitalized general and administrative and interest costs	18,961	18,210	19,665
Total costs incurred	$ 135,235	$ 182,461	$ 84,237

	For the Year-Ended December 31,		
	2012	2011	2010
Accumulated depreciation, depletion and amortization (DD&A)			
Balance, beginning of year	$ (1,265,603)	$ (1,175,553)	$ (1,082,381)
Provision for DD&A	(59,496)	(57,143)	(58,172)
Ceiling test writedown	(137,100)	(18,907)	—
Sale of proved properties and other (2)	(10,045)	(14,000)	(35,000)
Balance, end of year	$ (1,472,244)	$ (1,265,603)	$ (1,175,553)
DD&A per Mcfe	$ 1.75	$ 1.89	$ 1.88

(1) During 2012, the Company sold an additional portion of its Mississippian Lime acreage for $6.1 million. During 2011, the Company sold a portion of its unproved Mississippian Lime acreage for $14.5 million. During 2010, the Company recorded $36 million in consideration from the sale of a portion of its unevaluated acreage in the Woodford as part of its Woodford joint development agreement.

(2) During 2012, the Company sold its non-operated Arkansas assets for a net cash purchase price of $9.2 million. During 2011, the Company received an additional $14 million payment associated with the achievement of certain production metrics stipulated under the joint development agreement (See Note 3). During 2010, the Company recorded $35 million in consideration from the sale of a portion of its evaluated properties in the Woodford as part of its Woodford joint development agreement.

At December 31, 2012 and 2011, unevaluated oil and gas properties totaled $71.7 million and $70.4 million, respectively, and were not subject to depletion. Unevaluated costs at December 31, 2012 included $12.7 million of costs related to 17 exploratory wells in progress at year-end. These costs are expected to be transferred to evaluated oil and gas properties during 2013 upon the completion of drilling. At December 31, 2011, unevaluated costs included $5.9 million related to 44 exploratory wells in progress. All of these costs were transferred to evaluated oil and gas properties during 2012. The Company capitalized $7.0 million, $7.0 million and $7.8 million of interest during 2012, 2011 and 2010, respectively. Of the total unevaluated oil and gas property costs of $71.7 million at December 31, 2012, $24.8 million, or 35%, was incurred in 2012, $26.5 million, or 37%, was incurred in 2011 and $20.4 million, or 28%, was incurred in prior years. The Company expects that the majority of the unevaluated costs at December 31, 2012 will be evaluated within the next three years, including $28.3 million that the Company expects to be evaluated during 2013.

Note 13—Income Taxes

The Company typically provides for income taxes at a statutory rate of 35% adjusted for permanent differences expected to be realized, primarily statutory depletion, non-deductible stock compensation expenses and state income taxes. As a result of the ceiling test write-downs recognized during 2008 and 2009, the Company 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. Accordingly, the Company established a valuation allowance for a portion of the deferred tax asset. During 2011, the Company reversed the remaining valuation allowance as future reversals of existing deferred tax liabilities were sufficient to realize the entire deferred tax asset. However, as a result of the deferred tax benefit related to the ceiling test write-down in 2012, future reversals of existing deferred tax liabilities are no longer sufficient to realize the entire deferred tax asset. Thus, the Company re-established a valuation allowance for a portion of the deferred tax asset. The valuation allowance was $50.9 million as of December 31, 2012.

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

	December 31,		
	2012	2011	2010
Net operating loss carryforwards	$ 16,641	$ 2,409	$ 4,737
Percentage depletion carryforward	7,317	6,103	3,596
Alternative minimum tax credits	784	784	776
Contributions carryforward and other	156	130	90
Temporary differences:			
Oil and gas properties—full cost	22,716	(10,541)	(10,141)
Derivatives	(222)	(2,388)	405
Share-based compensation	3,474	2,952	3,732
Valuation allowance	(50,866)	—	(3,195)
Deferred tax liability	$ —	$ (551)	$ —

At December 31, 2012, the Company had approximately $56.4 million of operating loss carryforwards, of which $11.7 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 2032. The Company has available for tax reporting purposes $20.9 million in statutory depletion deductions that may be carried forward indefinitely.

Income tax expense (benefit) for each of the years ended December 31, 2012, 2011 and 2010 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,		
	2012	2011	2010
Amount computed using the statutory rate	$ (45,655)	$ 3,058	$ 17,065
Increase (reduction) in taxes resulting from:			
State & local taxes	(2,870)	192	1,073
Percentage depletion carryforward	(1,309)	(2,507)	(252)
Allowance for alternative minimum tax	—	8	575
Non-deductible stock option expense (1)	292	183	295
Share-based compensation (2)	9	346	3,041
Other	303	(300)	321
Change in valuation allowance	50,866	(2,790)	(20,488)
Income tax expense (benefit)	$ 1,636	$ (1,810)	$ 1,630

(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 recognized for tax purposes.

Note 14—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. At December 31, 2010 the Company had accrued $2.25 million in connection with estimated liabilities related to certain legal matters. All of these matters were settled during 2011, which resulted in an additional charge of $1.4 million included in other expense for the year ended December 31, 2011.

In January 2010, the Company recorded a gain relative to a $9 million cash settlement received from a lawsuit that was originally filed by the Company in 2008 relating to disputed interests in certain oil and gas assets purchased in 2007. The gain was reduced by approximately $0.8 million of costs incurred by the Company directly related to the settlement. In addition to the cash proceeds received, the Company was assigned additional working interests in certain producing properties. The Company recorded an additional $4.2 million non-cash gain representing the estimated fair market value of those interests on the effective date of the settlement, which represents a non-cash investing activity for purposes of the Statement of Cash Flows.

A portion of the production that the Company operates in Oklahoma is committed to a firm transportation agreement. Under the terms of the agreement, the Company must deliver 7.6 Bcf of natural gas during the period January 1 through October 31, 2013.

Lease Commitments

The Company has operating leases for office space and equipment, which expire on various dates through 2017. Future minimum lease commitments as of December 31, 2012 under these operating leases are as follows (in thousands):

2013	$ 1,211
2014	1,032
2015	1,026
2016	988
2017	898
Thereafter	—
	$ 5,155

Total rent expense under operating leases was approximately $1.4 million, $1.3 million and $1.1 million in 2012, 2011 and 2010, respectively.

Note 15—Oil and Gas Reserve Information—Unaudited

The Company's net proved oil and gas reserves at December 31, 2012 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.

During 2012, the Company's estimated proved reserves decreased by 14%. This decrease was primarily due to production, the sale of the Company's non-operated Arkansas assets and the significant decrease in the historical 12-month average price per Mcf of natural gas used to calculate estimated proved reserves which was $2.20 per Mcf at December 31, 2012 as compared to $3.34 per Mcf at December 31, 2011. This decrease was partially offset by the success of our Oklahoma,Texas and Gulf Coast drilling programs. In total, the Company added approximately 27 Bcfe of proved reserves in Oklahoma, 9 Bcfe from the La Cantera discovery and 28 Bcfe in the Carthage Field from horizontal drilling in the Cotton Valley during 2012. Overall, the Company had a 98% drilling success rate during 2012 on 107 gross wells drilled.

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 the continental United States:

	Oil in MBbls	NGL in MMcfe	Natural Gas in MMcf	Total Reserves in MMcfe
Proved reserves as of December 31, 2009	1,931	10,508	156,853	178,947
Revisions of previous estimates	187	187	20,958	22,267
Extensions, discoveries and other additions	168	150	47,681	48,839
Purchase of producing properties	—	—	2,336	2,336
Sale of reserves in place	—	—	(28,761)	(28,761)
Production	(663)	(2,472)	(24,501)	(30,951)
Proved reserves as of December 31, 2010	1,623	8,373	174,566	192,677
Revisions of previous estimates	(294)	308	8,418	6,962
Extensions, discoveries and other additions	595	8,627	82,113	94,310
Purchase of producing properties	43	91	1,292	1,641
Production	(572)	(2,288)	(24,463)	(30,183)
Proved reserves as of December 31, 2011	1,395	15,111	241,926	265,407
Revisions of previous estimates	215	(958)	(52,076)	(51,744)
Extensions, discoveries and other additions	647	14,572	46,390	64,844
Sale of reserves in place	(81)	—	(15,806)	(16,292)
Production	(521)	(3,365)	(27,466)	(33,957)
Proved reserves as of December 31, 2012	1,655	25,360	192,968	228,258
Proved developed reserves				
As of December 31, 2010	1,474	6,078	110,599	125,521
As of December 31, 2011	1,160	11,071	143,441	161,472
As of December 31, 2012	1,225	20,608	140,307	168,265
Proved undeveloped reserves				
As of December 31, 2010	149	2,295	63,967	67,156
As of December 31, 2011	235	4,040	98,485	103,935
As of December 31, 2012	430	4,752	52,661	59,993

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,		
	2012	2011	2010
Future cash flows	$ 748,914	$ 1,080,392	$ 810,131
Future production costs	(220,750)	(264,219)	(223,175)
Future development costs	(121,346)	(180,846)	(144,451)
Future income taxes	(10,205)	(86,612)	(41,156)
Future net cash flows	396,613	548,715	401,349
10% annual discount	(164,218)	(244,834)	(164,974)
Standardized measure of discounted future net cash flows	$ 232,395	$ 303,881	$ 236,375

Changes in Standardized Measure

	Year Ended December 31,		
	2012	2011	2010
Standardized measure at beginning of year	$ 303,881	$ 236,375	$ 174,288
Sales and transfers of oil and gas produced, net of production costs	(92,562)	(116,398)	(117,572)
Changes in price, net of future production costs	(138,842)	(10,219)	93,702
Extensions and discoveries, net of future production and development costs	104,066	178,901	42,028
Changes in estimated future development costs, net of development costs incurred during this period	69,499	915	5,803
Revisions of quantity estimates	(56,352)	11,236	46,373
Accretion of discount	34,137	25,565	17,700
Net change in income taxes	30,617	(18,215)	(16,568)
Purchase of reserves in place	—	4,805	1,478
Sale of reserves in place	(8,186)	—	(798)
Changes in production rates (timing) and other	(13,863)	(9,084)	(10,059)
Net increase (decrease) in standardized measure	(71,486)	67,506	62,087
Standardized measure at end of year	$ 232,395	$ 303,881	$ 236,375

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

	2012	2011	2010
Oil, $/Bbl	$102.81	$101.42	$79.72
Ngls, $/Mcfe	6.07	8.62	7.00
Natural Gas, $/Mcf	2.20	3.34	3.56

Note 16 - Summarized Quarterly Financial Information - Unaudited

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

	Quarter Ended			
	March 31	June 30	September 30	December 31
2012:				
Revenues	$ 36,041	$ 33,413	$ 33,951	$ 38,186
Loss from operations (1)	(18,314)	(52,183)	(35,919)	(24,027)
Loss available to common stockholders (1)	(18,608)	(54,520)	(38,639)	(25,451)
Earnings per share:				
Basic	$ (0.30)	$ (0.87)	$ (0.62)	$ (0.41)
Diluted	$ (0.30)	$ (0.87)	$ (0.62)	$ (0.41)
2011:				
Revenues	$ 41,603	$ 41,975	$ 39,029	$ 38,093
Income (loss) from operations (2)	3,178	(2,088)	4,749	2,899
Net income (loss) available to common stockholders (2)	1,897	(3,045)	3,727	2,830
Earnings per share:				
Basic	$ 0.03	$ (0.05)	$ 0.06	$ 0.04
Diluted	$ 0.03	$ (0.05)	$ 0.06	$ 0.04

(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, 2012 included ceiling test write-downs of $20.1 million, $53.5 million, $35.4 million and $28.1 million, respectively.

(2) Income (loss) from operations and net income (loss) available to common stockholders reported during the three months ended March 31 and June 30, 2011 included ceiling test write-downs of $5.9 million and $13.0 million, respectively.

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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 *#^
Vice President of Strategic Planning,
Franciscan Missionaries of Our Lady Health System

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

W. Todd Zehnder
Chief Operating Officer

Daniel G. Fournerat
Executive Vice President, General Counsel,
Chief Administrative Officer, and Secretary

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

Stephen H. Green
Senior Vice President,
Exploration

Mark K. Castell
Vice President - Oklahoma Assets

Edgar A. Anderson
Vice President - ArkLaTex

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1717 S. Boulder, Suite 201
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Transfer Agent and Registrar

American Stock Transfer & Trust Company
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Telephone: (718) 921-8145

Independent Auditors

Ernst & Young LLP
New Orleans, Louisiana 70170

Legal Counsel

Porter & Hedges, LLP
Houston, Texas 77002

Onebane Law Firm
Lafayette, Louisiana 70502

Annual Meeting

The Company's Annual Meeting of Stockholders will be held at 9:00 A.M. CDT on May 21, 2013, at the City Club at River Ranch at 221 Elysian Fields Dr., Lafayette, LA, 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

PQ
LISTED
NYSE

P E T R O Q U E S T . C O M

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