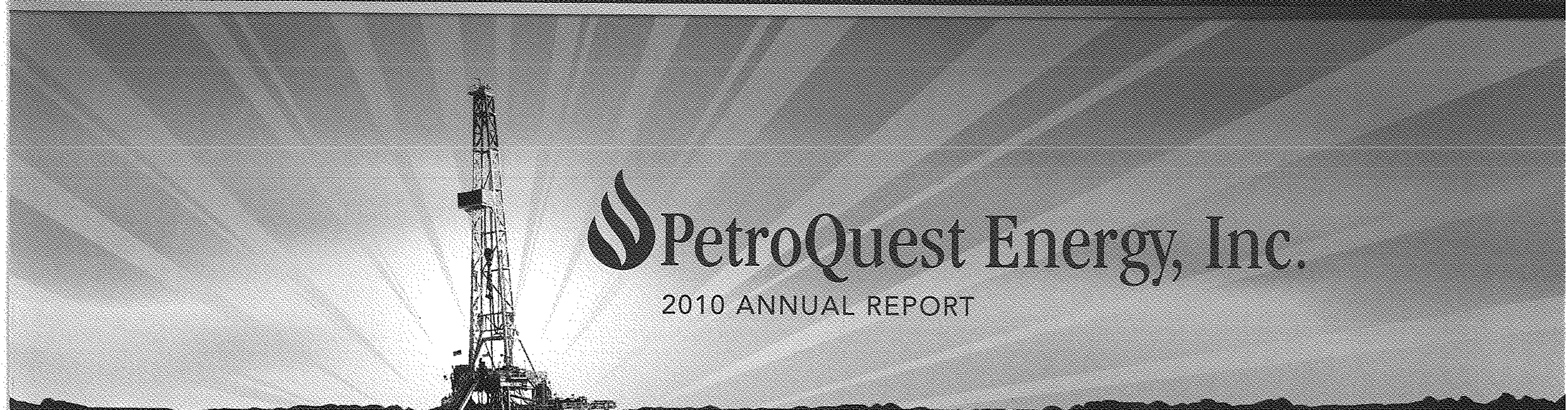
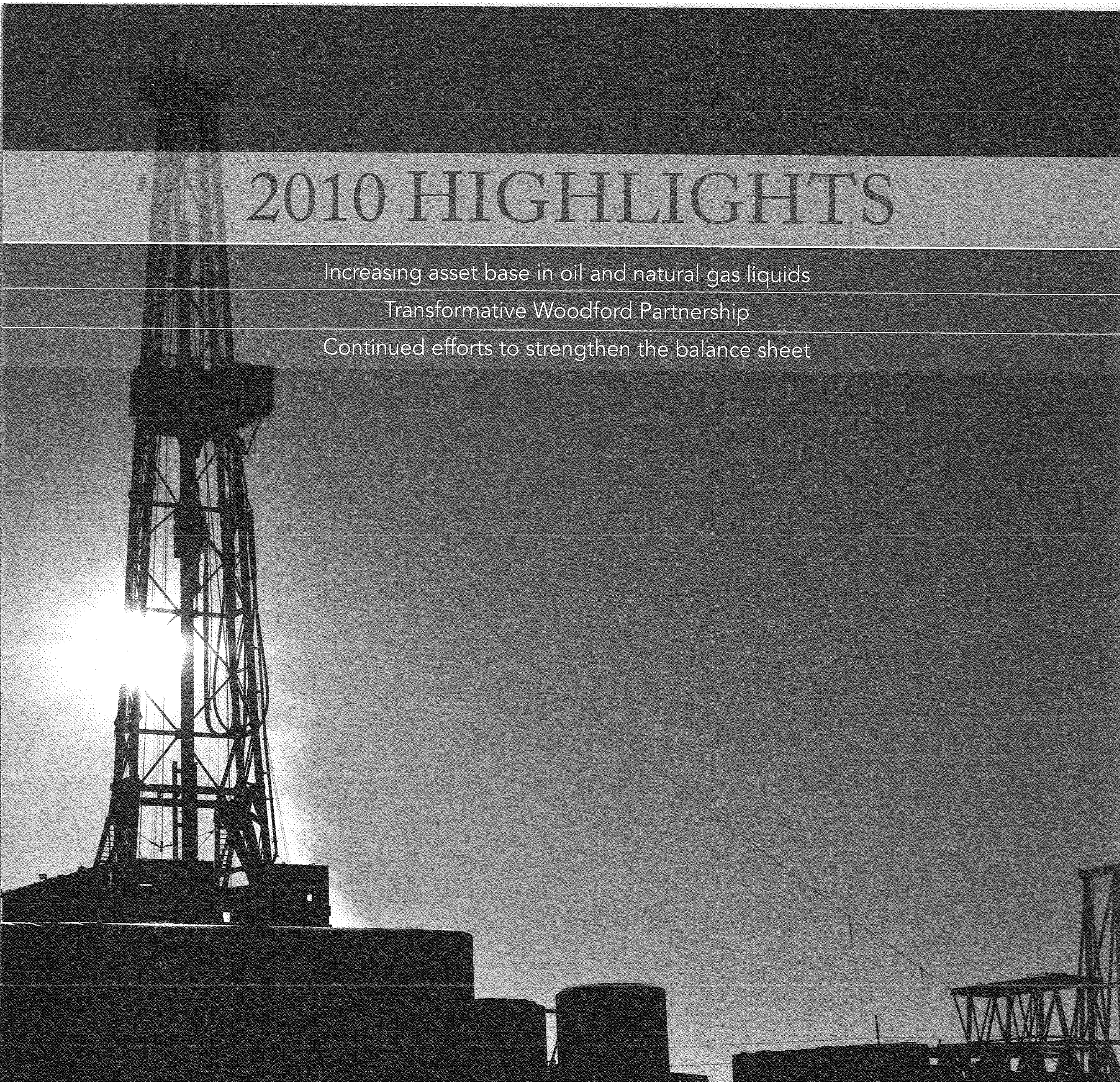


PetroQuest Energy, Inc.

2010 ANNUAL REPORT

NEW HORIZONS



2010 HIGHLIGHTS

Increasing asset base in oil and natural gas liquids

Transformative Woodford Partnership

Continued efforts to strengthen the balance sheet

Corporate Profile

PetroQuest Energy is a diversified exploration and production company with a long-term track record of delivering value to shareholders by focusing on low-risk, repeatable operations in long-life basins and resource trends such as the world-class Woodford and Fayetteville Shale plays as well the Eagle Ford and Niobrara oil plays in the United States.

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Financial & Operational Highlights

	2005 Annual	2006 Annual	2007 Annual	2008 Annual	2009 Annual	2010 Q1	2010 Q2	2010 Q3	2010 Q4	2010 Annual
Production										
Natural Gas, MMcf	11,188	19,106	22,650	27,032	28,065	6,245	5,812	6,195	6,249	24,502
NGL, MMcfe	870	2,422	2,316	2,676	2,533	615	594	614	647	2,470
Crude Oil, MBbl	665	695	1,080	681	600	145	154	190	174	663
Natural Gas, MMcfe	16,051	25,697	31,444	33,792	34,199	7,728	7,332	7,950	7,942	30,951
Financial ($ Thousands, except per share amounts)										
Total Revenues	$ 120,552	$ 199,520	$ 262,334	$ 313,958	$ 218,875	$ 47,614	$ 41,918	$ 46,285	$ 43,477	$ 179,294
Net Income (Loss)	21,417	23,986	40,619	(96,960)	(90,190)	30,997	6,535	6,226	3,368	47,126
Preferred Stock Dividends	--	--	1,374	5,140	5,140	1,280	1,287	1,287	1,285	5,139
Net Income (Loss) Available to Common Stockholders	$ 21,417	$ 23,986	$ 39,245	$ (102,100)	$ (95,330)	$ 29,717	$ 5,248	$ 4,939	$ 2,083	$ 41,987
Per Common Share: Basic	$ 0.46	$ 0.49	$ 0.79	$ (2.08)	$ (1.72)	$ 0.47	$ 0.08	$ 0.08	$ 0.03	$ 0.67
Diluted	$ 0.44	$ 0.49	$ 0.78	$ (2.08)	$ (1.72)	$ 0.46	$ 0.08	$ 0.08	$ 0.03	$ 0.66

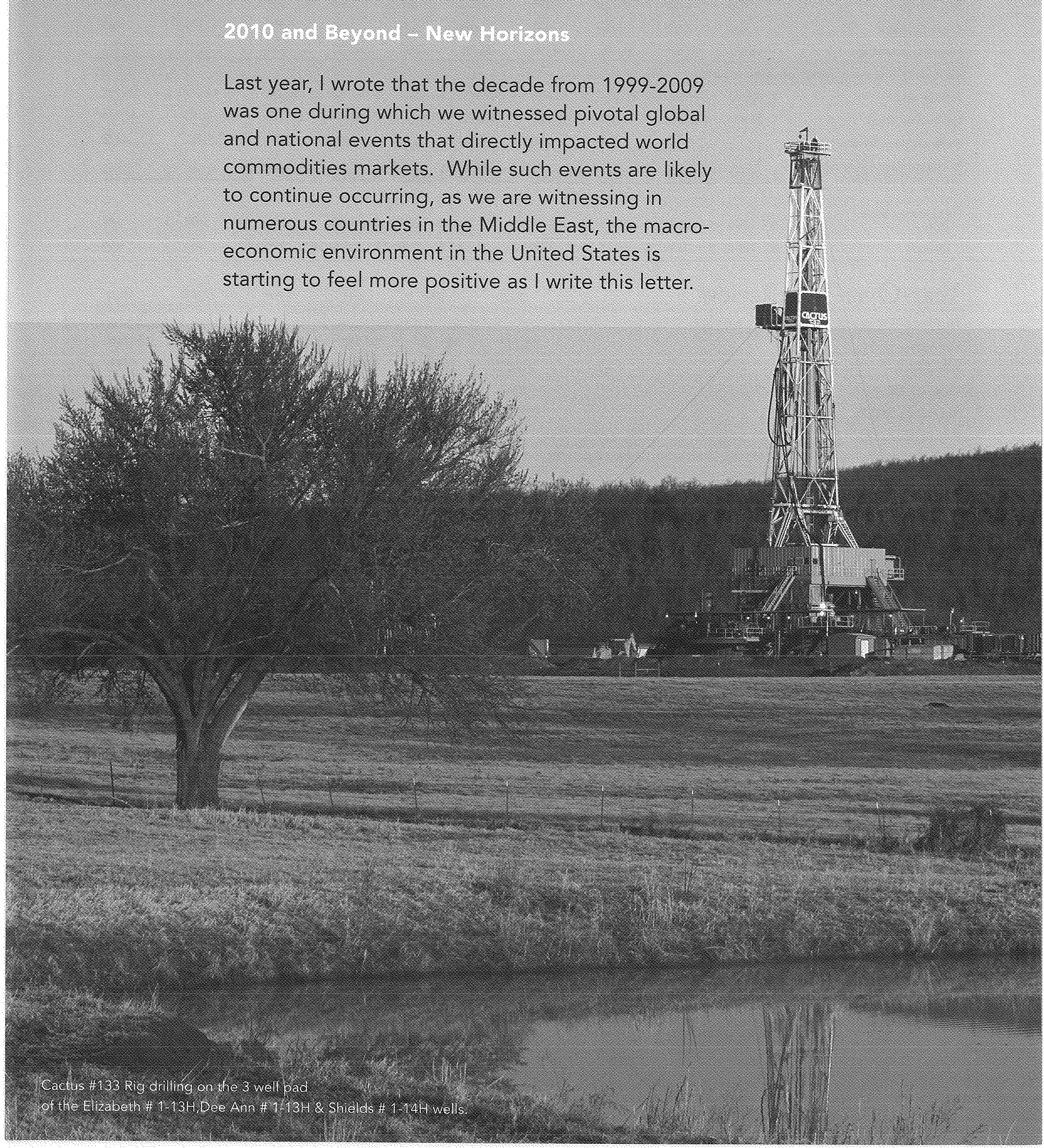
Year-Over-Year Review

	2005	2006	2007	2008	2009	2010
Reserves ($ Thousands, except per share amounts)						
Natural Gas, MMcf	98,097	108,128	129,154	158,781	156,853	174,566
NGL, MMcfe	11,018	10,025	13,314	13,405	10,508	8,373
Crude Oil, MBbl	3,642	2,731	2,342	2,201	1,931	1,623
Natural Gas, MMcfe	130,967	134,539	156,520	185,392	178,947	192,677
Percent Developed	69 %	72 %	69 %	73 %	62 %	65 %
Percent Dry Gas	75 %	80 %	83 %	86 %	88 %	91 %
Percent Gulf Coast	48 %	48 %	39 %	32 %	23 %	13 %
Future Undiscounted Net Cash Flows, $000s	$ 861,689	$ 516,013	$ 779,395	$ 466,449	$ 272,271	$ 442,505
SEC PV-10, Before Taxes, $000s	$ 639,734	$ 384,313	$ 540,651	$ 327,193	$ 176,995	$ 255,651
Commodity Prices						
PetroQuest Realized, Natural Gas, $/Mcf	$ 7.47	$ 7.04	$ 7.21	$ 8.00	$ 5.84	$ 4.37
Henry Hub Cash Market Average, Natural Gas, $/Mcf	8.89	6.73	6.97	8.89	3.94	4.37
PetroQuest Realized, NGL, $/Mcfe	5.32	6.46	7.93	9.76	5.38	7.78
PetroQuest Realized, Crude Oil, $/Bbl	45.76	60.91	70.52	97.49	68.57	79.47
WTI (Cushing) Spot Average, Crude Oil, $/Bbl	56.59	66.09	72.23	99.92	61.99	79.51
PetroQuest Realized, Natural Gas Equivalent, $/Mcfe	7.51	7.54	8.15	9.13	6.39	5.78
Statistics						
Reserve Replacement, Excluding Revisions, %	337 %	152 %	132 %	220 %	115 %	165 %
6-Year Reserve Replacement, Excluding Revisions, %						174 %
Finding & Development Costs, Excluding Revisions, $/Mcfe	$ 3.62	$ 4.36	$ 5.82	$ 4.82	$ 1.50	$ 1.65
6-Year Finding & Development Costs, Excluding Revisions, $/Mcfe						$ 3.96
Per Unit Analysis, $/Mcfe						
Total Revenues	$ 7.51	$ 7.76	$ 8.34	$ 9.29	$ 6.40	$ 5.79
Lease Operating Expense and Production Taxes	1.54	1.61	1.27	1.69	1.26	1.42
Gas Gathering Costs	0.08	0.14	0.13	0.07	0.01	0.00
Gross Operating Margin	5.89	6.01	6.94	7.53	5.13	4.37
Interest Expense	0.77	0.56	0.43	0.28	0.37	0.32
General and Administrative	0.46	0.59	0.67	0.69	0.55	0.69
Preferred Stock Dividends	--	--	0.04	0.15	0.15	0.17
Gross Cash Margin	$ 4.66	$ 4.86	$ 5.80	$ 6.41	$ 4.06	$ 3.19

LETTER TO STOCKHOLDERS

2010 and Beyond – New Horizons

Last year, I wrote that the decade from 1999-2009 was one during which we witnessed pivotal global and national events that directly impacted world commodities markets. While such events are likely to continue occurring, as we are witnessing in numerous countries in the Middle East, the macro-economic environment in the United States is starting to feel more positive as I write this letter.



Cactus #133 Rig drilling on the 3 well pad of the Elizabeth # 1-13H, Dee Ann # 1-13H & Shields # 1-14H wells.

Although it may still be unclear whether the global financial crisis has passed entirely, I can point to increasingly positive conditions for the long-term natural gas market in the U.S. These include beginnings of a recovery in industrial demand and the government's support for natural gas as a bridge fuel and key component to reduce dependence on foreign sources of fossil fuels. The President emphasized the nation's strategic goal to reduce our dependence on crude oil during his 2011 State of the Union address. Additionally, governors from various states have endorsed either drilling for natural gas or the usage of this fuel to either produce electricity in new plants or replace traditional fuels in certain transportation systems. Natural gas will play an increasingly critical role in our nation's energy security in the coming years if we are to achieve this strategic goal to reduce our reliance on imported oil.

PetroQuest has been and will remain bullish on the long-term future of natural gas, but we will adapt to changing market conditions over the near-term for the benefit of our shareholders. We are committed to growing gas production in our Woodford assets, and we will continue to be a gas-weighted company in terms of our reserves and production. However, 2010 was another challenging year as natural gas prices remained low because of the sluggish U.S. economy and the continuing trend of natural gas supply growth. In recognition of the challenges in near-term natural gas prices, we decided to explore new ways to expand PetroQuest's production and reserve base to gain more exposure to the oil and natural gas liquids markets, both of which are likely to outperform the natural gas market in 2011.

We focused on diversifying our production and reserve mix in 2010 by increasing our exposure to oil and natural gas liquids. We did this by expanding our relationship with our Woodford joint venture partner, NextEra Energy Resources. The initial focus of this joint venture was our Woodford Shale project, but we have now expanded this relationship into other long-lived resource plays such as the Eagle Ford play and the emerging Niobrara trend. The Niobrara is a geologic formation that stretches from New Mexico to Canada. Although it has been known to exist for many years and limited to a number of fields, development on a much larger regional basis has only recently become economically viable with the advent of advanced drilling techniques such as those PetroQuest utilizes on our Woodford shale acreage. Our non-operated position allows us to build Niobrara expertise over the next several quarters, which in turn will enable us to potentially expand our involvement as an operator in this exciting play. This is the same strategy we've used successfully in other plays during the past decade, namely entering projects with a non-operated position and eventually expanding our acreage into operatorship as we build our drilling and completion expertise. I am excited about this new area for PetroQuest, and we believe the Niobrara will be accretive to our cash flow, production and reserve totals as well as our overall mix between natural gas and liquids production.

Our joint venture partnership is a significant milestone in PetroQuest's development. What began as a way for us to capitalize and accelerate the development of our Woodford shale acreage continues to evolve into a broader relationship that will enable PetroQuest to expand our operations into other basins. As with most things PetroQuest does, the partnership is evolutionary, not revolutionary, in that the face of PetroQuest will not change. Our Woodford acreage continues to be our focus area, but we are in a position to begin examining other opportunities as well. I think 2011 is going to be one of the most exciting years in PetroQuest's history.

Before reviewing 2010 results, I want to commend every member of the PetroQuest team for their superb performance last year. We faced a number of headwinds in the natural gas industry, ranging from a challenging commodity price environment to continued weakness in the wider U.S. economy in 2010. Our people are the best in the business, and our team navigated PetroQuest through uncertain macro-economic times to emerge both stronger and more resilient as we move into a new decade. As shareholders, I am sure you are proud of the performance and confident of the ability of the PetroQuest team to deliver positive results as we continue on our growth trajectory in 2011.

2010 – Pivotal Year in Review

In 2010 we continued to expand the percentage of our production and reserves in long-life resource plays. By the end of last year, 87% of our reserves and 54% of our production was coming from our onshore resource assets. We added Niobrara acreage in Wyoming to the portfolio last year which we believe will grow PetroQuest's oil production as this emerging oil play develops. We also established a leasehold position in the Eagle Ford shale, and our Gulf Coast assets continue to underpin our oil production with steady performance. In the Woodford, the joint venture we signed in 2010 allows us to accelerate the development of our position in the play to deliver greater shareholder value, and I expect production volumes and reserves to continue growing from this core PetroQuest asset.

As we move toward new horizons, we continue to adhere to our guiding principles that have helped shape PetroQuest into an industry-leading independent oil and gas company. They are:

- Manage growth with an established strategy of balancing exploration, development and acquisitions;
- Build a company with assets that provide stable cash flow from reliable development drilling and effective management of operating costs;
- Retain a high level of operatorship to manage our pace of growth;
- Focus on long-term opportunities.

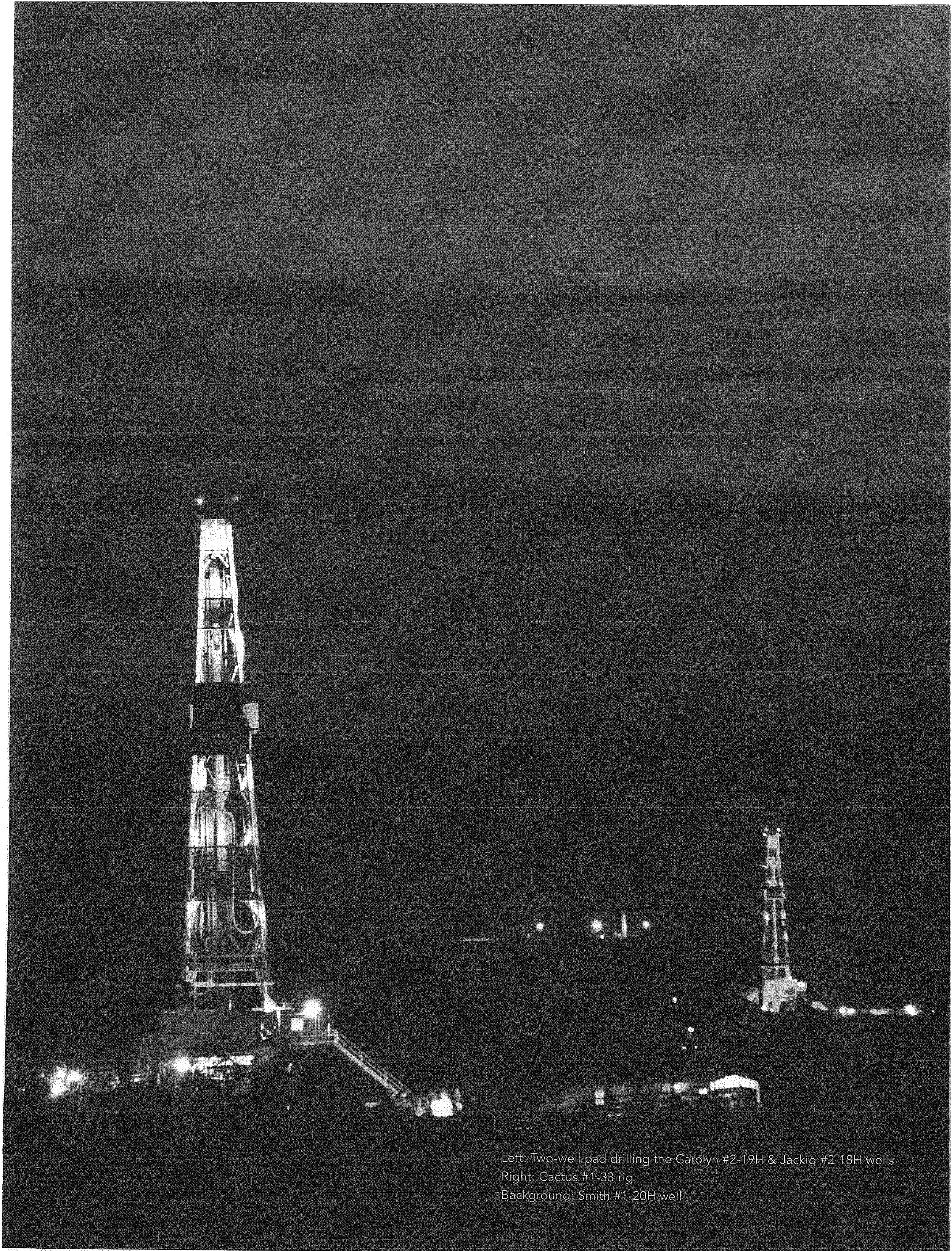
Adherence to these principles as part of our everyday business operations helped PetroQuest to successfully weather the economic downturn which began in 2008 and continued through 2010. The decision to slow our drilling activity in 2009 positioned PetroQuest to grow last year. In 2010, we invested $84 million, generated $120 million in cash flow, and drilled 102 wells across our portfolio. Despite depressed gas prices and rising service costs in 2010, we achieved the highest net income in the company's history at $42 million and the lowest quarterly net debt (adjusted for working capital) level of $88 million during the second quarter of 2010, all while growing reserves and internally funding capital spending. We improved our financial flexibility by refinancing our 10 3/8% senior notes due in 2012 to 10% senior notes due in 2017, and maintained low net debt by having zero dollars drawn on our line of credit and increasing cash reserves.

The Woodford Shale: A Good Place to be for Strength and Stability

In 2010, we drilled and completed nine operated wells in the Woodford with a 100% success rate and have driven cost per lateral foot to $300, down 61% versus 2008. We began the year with one operated rig working in the basin, and, as a result of the joint venture, we added a second rig during the third quarter of 2010. As I write this letter we are currently running three rigs. PetroQuest has approximately 45,000 net acres under lease in the Woodford, and we are now in a position to sustain double-digit growth in our Woodford assets.

In 2010, we reported reaching total depth on our 43rd Woodford operated horizontal well, and we continue to refine our drilling techniques to improve well performance. Our experience in the play leads us to believe that future development in the Woodford will utilize long lateral, 5,000+ foot, multi-frac stage wells. In the last three years, our estimated ultimate recovery per well has increased to 5.0 billion cubic feet of gas (Bcf). The company's daily net production from our Oklahoma assets increased approximately 17% since we resumed our development program for the Woodford in the fourth quarter of 2009. We continue to improve the performance of our Woodford assets and believe this play remains one of the most competitive shale gas basins in North America.

In May 2010 we announced a Woodford Shale joint venture agreement with two subsidiaries of NextEra Energy Resources. NextEra acquired 29 Bcf of our Woodford proved undeveloped reserves, a right to earn a 50% interest in our Woodford undeveloped acreage, and agreed to pay a share of our costs and expenses during the first drilling phase of the joint venture. The $60 million in cash proceeds recorded from this joint venture has contributed to our achieving the best financial condition in the company's history.



Left: Two-well pad drilling the Carolyn #2-19H & Jackie #2-18H wells
Right: Cactus #1-33 rig
Background: Smith #1-20H well

New Oil Plays

With ongoing success in the Woodford as a solid foundation, I am excited about our expansion in the Niobrara exploration project which I believe will add production upside as we increase PetroQuest's exposure to oil. During the year we accumulated a 25% working interest position in 20,000 acres in Wyoming prospective for the Niobrara oil shale play located in the Denver-Julesburg (DJ) Basin. The DJ Basin has been one of North America's most consistent sources of production over many decades, and the development of deeper zones, called the Niobrara, illustrates the opportunity for redevelopment of older oil fields using new horizontal drilling technology.

We completed our first two test wells in the Niobrara formation in November 2010. The presence of natural fracturing largely determines the viability of wells in the Niobrara, and our wells were designed to test the geology on our acreage in order to determine the best drilling and completion techniques for future wells. PetroQuest plans to participate in 10 to 15 gross wells in the southern Wyoming portion of the Niobrara in 2011.

In addition, PetroQuest established our initial leasehold position in the Eagle Ford Shale trend, where we have acquired 1,600 net acres in Dimmit and LaSalle Counties, Texas. We intend to drill three operated wells in this area during 2011, the first of which should spud during the second quarter.

Focus on Returns and Future Growth

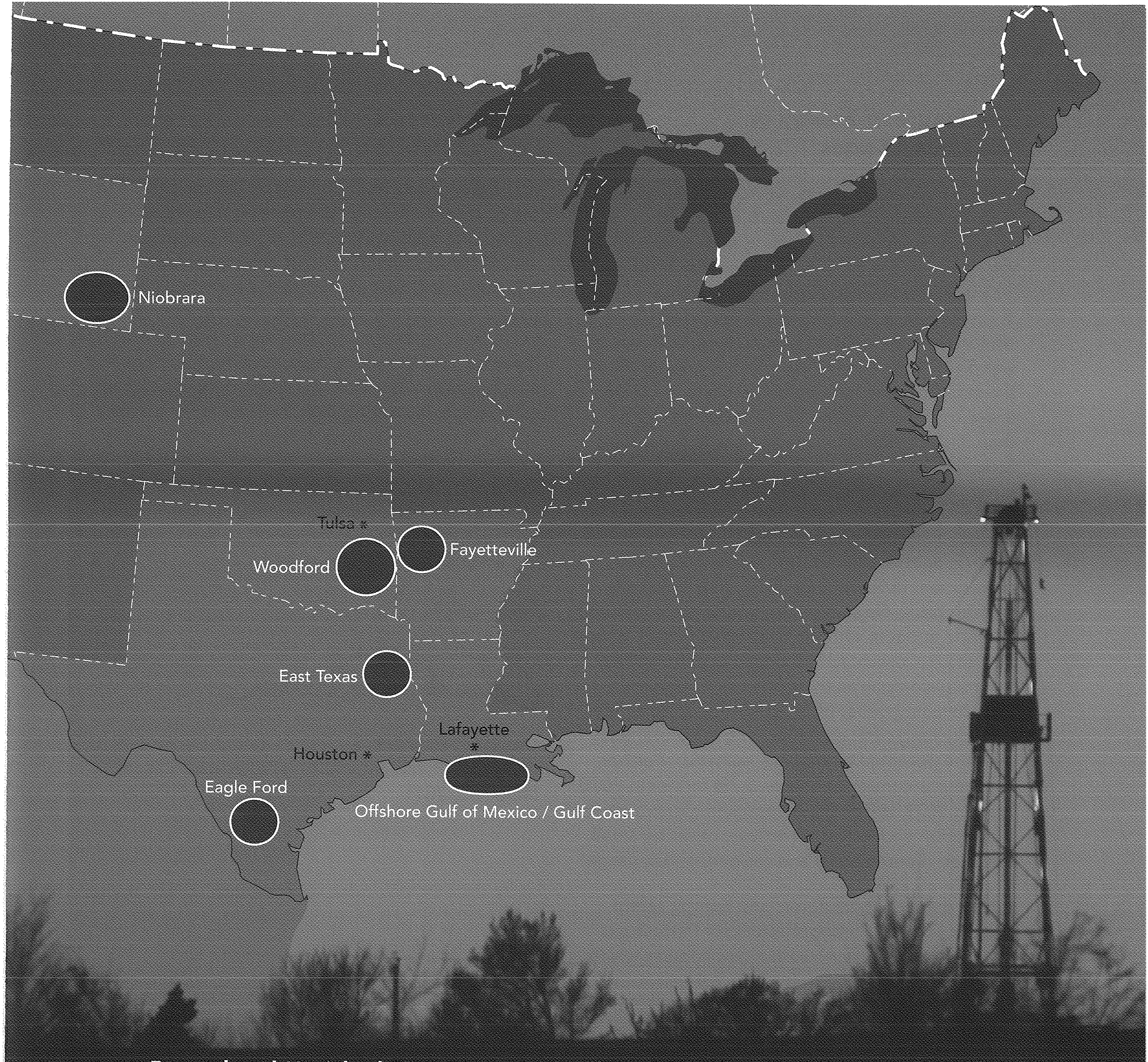
As of December 31, 2010, PetroQuest had a record high 193 Bcfe of proved reserves with a pre-tax PV-10 value of $256 million based on the average benchmark NYMEX prices of $4.38 per Mcf and $79.43 per barrel for the twelve months of 2010. Ninety-one percent of our proved reserves are natural gas, and 87% of our reserves are located in long-lived basins, up from 77% last year. Importantly, 65% of our reserves are proved developed. With this sizable reserves base, we have many years of built-in production growth in our project portfolio.

Oil and natural gas liquids (NGLs) now constitute 21% of our total production, and account for approximately 40% of our 2010 revenues. We grew oil production 11% in 2010, grew total reserves 24% (excluding the impact of reserves sold), and forecast oil growth of 10% or higher in 2011. We continue to move to a more liquids-balanced production stream by exploiting our existing inventory as well as seeking new acreage positions in emerging liquid-rich trends. The average monthly price for oil during 2010 traded at 18 times the equivalent natural gas price, higher than the standard six-to-one energy equivalent ratio. In this type of commodity price environment, we have a responsibility to our shareholders to focus our attention on the assets that will generate the highest rate of return. This is not to suggest our attention has been diverted from our shale gas assets; gas prices will eventually recover to more competitive price levels. Strategically, we are well-positioned with a diverse asset portfolio to focus operationally on those oil or gas projects that will provide the best returns for our shareholders.

Looking Ahead: Growth through Financial Flexibility

With zero drawn on our $100 million revolver, $63 million in cash and our disciplined capital strategy, we have the ability to not only ride out this turbulent period but actually grow PetroQuest while spending within cash flow. We will be able to fund our 2011 capital budget through cash flow from operations and proceeds from our Woodford joint venture despite adding new acreage and drilling opportunities to our project portfolio.

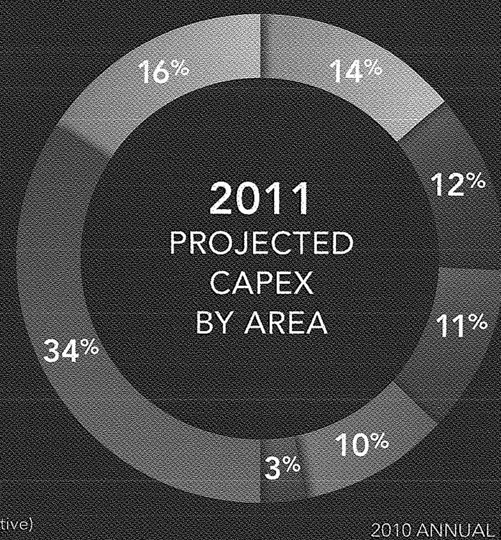
In 2011, we plan to allocate 34% of our capital budget to our Woodford projects, 16% to our East Texas projects, 14% to Onshore Louisiana, 12% to the Eagle Ford shale, 11% to Offshore Louisiana, 10% to the Niobrara, and 3% to our Fayetteville acreage. The diversity of these assets and our ability to fund projects in a variety of areas within cash flow demonstrate the success of our diversification strategy and the ongoing strength of our team to acquire and develop world-class resource plays.



Proved and Unrisked Reserves

Asset	1P (1)	Inventory (2)
Woodford	117	440(3)
East Texas	26	524(4)
Fayetteville	24	318
Offshore Gulf of Mexico	17	134
Gulf Coast	8	32
Niobrara	1	13
Eagle Ford	-	16
TOTAL	**193**	**1,495**

(1) Reserves are as of December 31, 2010 (reserves are net and in Bcfe)
(2) Unrisked inventory as of December 31, 2010 (net in Bcfe)
(3) Assumes JV partner participates in Phase 2 of the drilling carry
(4) Includes Bossier Shale of 359 net BCFE (160 acre spacing, 60% of acreage productive)



The Future of Energy in the United States

For the past several years, we have experienced turbulent and uncertain macro-economic conditions. However, things appear to be improving as the U.S. economy added another 113,000 jobs in December 2010 for a total of 1.1 million new private jobs created in 2010, while the United States' Gross Domestic Product was $14.7 trillion in Q3'10, which is greater than the pre-recession high of $14.5 trillion in Q3'08. It seems the U.S. economy is producing more than it was before the recession, with 6.1 million fewer workers.

Declining prices for natural gas have not been entirely negative because natural gas is now cost-competitive with thermal coal for power generation. In November 2010, on a dollar per MMBtu basis, New York hub natural gas continued to trade at parity with the Central Appalachian coal hub price. Continued low prices and the ability for utility companies to hedge prices provide the electricity generation sector the opportunity to make long-term commitments to natural gas with the potential to increase demand. Further, natural gas consumption was 5.7% higher in 2010 than in 2009, driven by increases in electric power generation and industrial activity, offset by small declines in commercial and residential gas usage.

I think the recent economic and energy sector statistics point to a bright future for PetroQuest. We have a uniquely powerful joint venture which provides the financial strength to diversify our production and reserve mix in order to capitalize on favorable changes in oil, natural gas liquids, or dry natural gas prices. We have an asset base with built-in organic growth through the drill bit, and the U.S. economy appears to be improving. Lastly, I believe the regulatory posture of governments, particularly the Federal government, will inevitably lead to natural gas playing a larger role in the energy security for the U.S. moving forward.

PetroQuest has delivered positive results over the past decade, and I think we are in a better position to continue delivering growth for the benefit of our shareholders than perhaps at any other time in the company's history. We have an extensive track record of growth with a 28% 12-year compound annual growth rate (CAGR) in production and a 25% 12-year CAGR in reserves. Additionally we have a 97% drilling success rate for the past six years while operating approximately 90% of our reserves. The company plans to combine longer-life development assets like its Woodford program with shorter-life strong cash flow generating assets like its Gulf Coast program in an effort to diversify its asset portfolio. In the oil and gas business, success is driven by the team and the assets; on both counts, PetroQuest is among the best in the business, and I am as positive about the future of our company as I have ever been.

Best regards,

Charles T. Goodson

Charles T. Goodson
Chairman, President and Chief Executive Officer
March 15, 2011

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

(Mark One)

[X] Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2010
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)

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

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
Preferred Stock Purchase Rights	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 [X] 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 [X] 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.
[X] 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 [X] 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 [X] No

The aggregate market value of the voting common equity held by non-affiliates of the registrant was approximately $291,000,000 as of June 30, 2010 (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 21, 2011, the registrant had outstanding 63,210,082 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 12, 2011, 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 half 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 effect of new SEC rules on our estimates of proved reserves;
- 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 48.

PART I

ITEMS 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, Gulf Coast Basin, Arkansas 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, Arkansas, 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 2010, we have invested approximately $733 million into growing our longer life assets. During the seven year period ended December 31, 2010, we have realized a 94% drilling success rate on 653 gross wells drilled. Comparing 2010 metrics with those in 2003, the year we implemented our diversification strategy, we have grown production by 220% and estimated proved reserves by 131%. At December 31, 2010, 87% of our estimated proved reserves and 54% of our 2010 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 thus allowing us to utilize our cash flow from operations, combined with proceeds from an equity offering, to repay $130 million of bank debt since the end of 2008. 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.

During 2010 we refocused on the key elements of our business strategy with the goal of growing reserves and production in a fiscally prudent manner. To that end, 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 million in cash at closing, net of $2.6 million in transaction fees, and will receive an additional $14 million on November 30, 2011. If certain production performance metrics are achieved, we will receive an additional $14 million, which we estimate could occur during 2011. Additionally, WSGP will fund a share of our future drilling costs under a long-term drilling program. The additional capital provided by this agreement allows us to accelerate the pace of our development of the Woodford Shale and pursue opportunities in other basins.

Business Strategy

Maintain Our Financial Flexibility. Because we operate approximately 70% of our total estimated proved reserves and manage the drilling and completion activities on an additional 11% of such reserves, we expect to be able to control the timing of a substantial portion of our capital investments. Our 2011 capital expenditures, which include capitalized interest and overhead, are expected to range between $110 million and $120 million. In order to maintain our financial flexibility, we plan to fund our 2011 capital expenditures budget with cash flow from operations and $14 million in additional proceeds to be received in 2011 under the Woodford joint development agreement. We expect to be able to actively manage our 2011 capital budget in the event commodity prices or the health of the global financial markets do not match our expectations. During 2011, we also plan to also maintain a commodity hedging program and, as we did during prior years, we may opportunistically dispose of non-core or mature assets to provide capital for higher potential exploration and development properties that fit our long-term growth strategy.

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 2011 capital investments in a manner that continues to geographically and operationally diversify our asset base. Through our portfolio diversification efforts, at December 31, 2010, approximately 87% of our estimated proved reserves were located in longer life and lower risk basins in Oklahoma, Arkansas, Texas and Wyoming and 13% were located in the shorter life, but higher flow rate reservoirs in the Gulf Coast Basin. This compares to 77% and 68% of our estimated proved reserves located in longer life basins at December 31, 2009 and 2008, respectively. In terms of production diversification, during 2010, 54% of our production was derived from longer life basins versus 53% and 47% in 2009 and 2008, respectively. In order to further balance our production profile, we grew oil production by 11% in 2010 and plan to increase oil production in 2011 by 10%.

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. We intend to primarily target properties that provide us with exposure to longer life 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 2010, we established positions targeting the Niobrara Shale in Wyoming and the Eagle Ford Shale in Texas.

Concentrate in Core Operating Areas and Build Scale. We plan to continue focusing on our operations in Oklahoma, Wyoming, 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 the majority of these regions. We believe that these factors, coupled 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. Since 2003, 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.

2010 Financial and Operational Summary

During 2010, we invested $84.2 million in exploratory, development and acquisition activities, which is net of approximately $36 million in consideration received from the sale of unevaluated leasehold in conjunction with the Woodford joint development agreement. We drilled 85 gross exploratory wells and 17 gross development wells realizing an overall success rate of 97%. These activities were financed through our cash flow from operations. During 2010, our production decreased 9% to 31 Bcfe as a result of the reduced capital expenditures during 2009. Our proved reserves increased 8% from 2009 as discussed in greater detail below.

In August 2010, we issued $150 million in principal amount of 10% Senior Notes due 2017 (the "Notes") in a public offering. The net proceeds of the offering, together with cash on hand, were used to fund the tender offer and consent solicitation and redemption of our 10 3/8% Senior Notes due 2012. We incurred a loss totaling $6 million relating to the early retirement of the 10 3/8% Senior Notes. Approximately $1.8 million of the loss related to non-cash amortization of deferred financing costs and discount associated with the 10 3/8% Senior Notes.

Oil and Gas Reserves

In 2009, the SEC issued a revision to Staff Accounting Bulletin 113 ("SAB 113") which changed the guidelines for estimating proved reserves effective for reserve estimates beginning December 31, 2009. The principal revisions include: the price used in determining quantities of oil and gas reserves; elimination of post-quarter-end prices to evaluate limitations of capitalized costs under the full cost method of accounting; 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; and removal of the exclusion of unconventional oil and gas extraction methods as oil and gas producing activities. Our reserves were primarily affected by the change in pricing methodology, which is now calculated by the unweighted arithmetic average of the first-day-of-the-month market price for oil and gas during the 12-month period prior to the ending date of the balance sheet.

Our estimated proved reserves under the revised SEC guidelines at December 31, 2010 increased 8% from 2009 totaling 1,623 MBbls of oil, 8,373 MMcfe of natural gas liquids (Ngls) and 174,566 MMcf of natural gas, with a pre-tax present value, discounted at 10%, of the estimated future net revenues based on average prices during 2010 ("PV-10") of $256 million. At December 31, 2010, our standardized measure of discounted cash flows, which includes the estimated impact of future income taxes, totaled $236.4 million. Our standardized measure of discounted cash flows at December 31, 2010 was 36% higher than 2009 as we utilized prices of $79.72 per barrel of oil, $7.00 per Mcfe of Ngls and $3.56 per Mcf of natural gas (adjusted for field differentials), compared to $60.57 per barrel of oil, $4.89 per Mcfe of Ngls and $2.84 per Mcf of natural gas (adjusted for field differentials) at December 31, 2009. See the reconciliation of PV-10 to the standardized measure of discounted cash flows below.

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, 2010. Our internal reservoir engineering staff is managed by an individual with 29 years of industry experience as a reservoir and production engineer, including eight 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, 2010.

	Oil (MBbls)	NGL (Mmcfe)	Natural Gas (Mmcf)	Total Mmcfe*
Proved Developed	1,474	6,078	110,599	125,521
Proved Undeveloped	149	2,295	63,967	67,156
Total Proved	1,623	8,373	174,566	192,677

* 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, 2010, our proved undeveloped reserves ("PUDs") totaled 67.2 Bcfe, a 1% decrease from our PUD balance at December 31, 2009. During 2010, we spent $2.3 million converting 2.4 Bcfe of PUDs at December 31, 2009 to proved developed at December 31, 2010. In addition, during 2010 we sold approximately 29 Bcfe of Woodford shale PUDs to WSGP. Offsetting these decreases to PUDs were our positive drilling results and performance revisions related to our Oklahoma and Arkansas assets and an increase totaling approximately 11.1 Bcfe as a result of higher pricing. Following is an analysis of the change in our PUDs as of December 31, 2010:

	Mmcfe
PUD Balance at December 31, 2009	67,867
PUDs converted to proved developed	(2,423)
PUDs added from revisions or extensions and discoveries	25,814
PUDs sold	(28,761)
PUDs removed for 5 year rule	(6,444)
PUDs added due to pricing	11,103
PUD Balance at December 31, 2010	67,156

Approximately 70% of our total PUDs at December 31, 2010 were associated with the future development of our Oklahoma properties. We expect all of our PUDs at December 31, 2010 to be developed over the next five years. At December 31, 2010, 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 $47 million in 2011, $58 million in 2012 and $5 million in 2013.

The estimated cash flows from our proved reserves at December 31, 2010 were as follows:

	Proved Developed (M$)	Proved Undeveloped (M$)	Total Proved (M$)
Estimated pre-tax future net cash flows (1)	$360,040	$82,465	$442,505
Discounted pre-tax future net cash flows (PV-10) (1)	$239,332	$16,319	$255,651
Total standardized measure of discounted future net cash flows			$236,375

(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, 2010:

	Total Proved (M$)
Estimated pre-tax future net cash flows	$442,505
10% annual discount	(186,854)
Discounted pre-tax future net cash flows	255,651
Future income taxes discounted at 10%	(19,276)
Standardized measure of discounted future net cash flows	$236,375

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, 2010 and 2009.

	2010		2009	
	Reserves	Production	Reserves	Production
Oklahoma	117.0	10.6	98.5	10.6
Texas	26.1	3.5	29.8	4.3
Gulf Coast Basin	25.6	14.4	40.9	16.3
Arkansas	23.6	2.5	9.8	3.0
Wyoming	0.4	-	-	-
	192.7	31.0	179.0	34.2

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 2010, we continued our evaluation of the Woodford Shale as we drilled and participated in 20 gross wells, achieving a 100% success rate. In total, we invested $15.9 million in Oklahoma during 2010 acquiring prospective Woodford Shale acreage and drilling and completing wells, which was net of approximately $36 million of consideration received from the sale of unevaluated leasehold in conjunction with our joint development agreement with WSGP. Average daily production from our Oklahoma properties during 2010 totaled 29 MMcfe per day. We experienced positive performance and pricing revisions to our proved reserves, which when combined with reserves added from our 2010 drilling program, and offset by approximately 29 Bcfe of PUDs sold to WSGP, resulted in a 19% increase in our estimated proved reserves. We have allocated approximately 34% of our 2011 capital budget to operations in Oklahoma as we expect to operate the drilling of approximately 30 gross wells.

Texas

During 2010, we invested $6.9 million in our Texas properties as we participated in two gross wells in our Carthage field, achieving a 100% success rate and acquired prospective acreage in the Eagle Ford Shale formation. Net production from our Texas assets averaged 9.5 MMcfe per day during 2010, a 19% decrease from 2009 average daily production and our estimated proved reserves declined 12% from 2009, primarily as a result of reduced capital investments during 2009 and 2010. We have allocated approximately 28% of our 2011 capital budget to drilling and completing wells in our Carthage field and the recently acquired acreage in the Eagle Ford Shale.

Gulf Coast Basin

During 2010, we drilled and/or participated in four gross wells, achieving a 50% success rate. In total, we invested $36 million in this area, including recompletions and plugging and abandonment activities. Production from this area decreased 12% from 2009 totaling 39.5 MMcfe per day in 2010. In addition, our estimated proved reserves in this area declined 37% from 2009 primarily as a result of reduced capital investments during 2009 and 2010. We have allocated approximately 25% of our 2011 capital budget to various drilling and maintenance projects in the Gulf Coast Basin.

Arkansas

During 2007, we acquired a leasehold position in Arkansas and began participating in an aggressive drilling program targeting the Fayetteville Shale. This drilling program continued during 2010 as we participated in 74 gross wells, all of which were successful. In total we invested $9.4 million in Arkansas during 2010. Production during 2010 approximated 2009 amounts while our estimated proved reserves increased by approximately 142% during 2010. The growth in proved reserves during 2010 was the result of our drilling program, positive performance and pricing revisions, as well as the settlement of a lawsuit whereby we were awarded additional interests in certain properties. We have allocated approximtely 3% of our 2011 capital budget to participating in third-party operated Fayetteville Shale wells.

Wyoming

During 2010, we acquired a 25% interest in acreage targeting the Niobrara Shale in Wyoming. In total, we invested $4.1 million in our Wyoming assets participating in two gross wells, achieving a 50% success rate, and acquiring prospective acreage. We have allocated approximately 10% of our 2011 capital budget to participating in third-party operated wells in Wyoming.

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 9.1 Bcf of natural gas per year through October 31, 2013. Based upon our current proved reserves and on the significant capital spending that we intend to allocate to this area, 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 2010, one customer accounted for 19%, two accounted for 17% each and one accounted for 10% of our oil and natural gas revenue. During 2009, two customers accounted for 17% each, one accounted for 13% and one accounted for 12% of our oil and natural gas revenue. During 2008, one customer accounted for 23%, three accounted for 11% 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 one core area, Oklahoma, which includes primarily Woodford Shale reserves, represented greater than 15% of our total estimated proved reserves.

	Year Ended December 31,		
	2010	2009	2008
Production:			
Oil (Bbls):			
Oklahoma	71	502	330
Other	663,231	599,622	680,241
Total Oil (Bbls)	663,302	600,124	680,571
Gas (Mcf):			
Oklahoma	10,577,414	10,579,524	9,174,993
Other	13,924,126	17,485,746	17,856,808
Total Gas (Mcf)	24,501,540	28,065,270	27,031,801
NGL (Mcfe):			
Oklahoma	683	450	342
Other	2,469,188	2,532,372	2,676,061
Total NGL (Mcfe)	2,469,871	2,532,822	2,676,403
Total Production (Mcfe):			
Oklahoma	10,578,523	10,582,986	9,177,315
Other	20,372,700	23,615,850	24,614,315
Total Production (Mcfe)	30,951,223	34,198,836	33,791,630
Average sales prices (1):			
Oil (per Bbl):			
Oklahoma	$69.62	$52.13	$85.33
Other	$79.48	$59.31	$100.62
Total Oil (per Bbl)	$79.47	$59.31	$100.61
Gas (per Mcf)			
Oklahoma	$2.80	$2.27	$6.33
Other	$4.31	$3.74	$9.20
Total Gas (per Mcf)	$3.66	$3.19	$8.22
NGL (per Mcfe)			
Oklahoma	$3.79	$4.10	$9.67
Other	$7.78	$5.38	$9.76
Total NGL (per Mcfe)	$7.78	$5.38	$9.76
Total Per Mcfe:			
Oklahoma	$2.80	$2.27	$6.33
Other	$6.47	$4.86	$10.51
Total Per Mcfe	$5.22	$4.06	$9.38
Average Production Cost per Mcfe (2):			
Oklahoma	$0.71	$0.53	$0.74
Other	$1.55	$1.39	$1.54
Total Average Production Cost per Mcfe	$1.26	$1.13	$1.32

(1) Does not include the effect of hedges.

(2) Production costs do not include production taxes.

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.

	2010		2009		2008	
	Gross	Net	Gross	Net	Gross	Net
Exploration:						
Productive	82	9.55	64	5.84	103	27.64
Non-productive	3	0.76	2	0.48	6	1.63
Total	85	10.31	66	6.32	109	29.27
Development:						
Productive	17	1.50	16	1.70	41	10.77
Non-productive	-	-	-	-	-	-
Total	17	1.50	16	1.70	41	10.77

In 2010, 19 gross (7.32 net) exploratory and 1 gross (.81 net) development wells were drilled targeting the Woodford Shale. In 2009, 13 gross (2.56 net) exploratory and 2 gross (.93 net) development wells were drilled in the Woodford Shale. In 2008 we drilled 21 gross (10.85 net) exploratory and 7 gross (4.27 net) development Woodford Shale wells. All of these wells were productive.

We owned working interests in 19 gross (11 net) producing oil wells and 1004 gross (289 net) producing gas wells at December 31, 2010. Of the 1,023 gross productive wells at December 31, 2010, 7 had dual completions. At December 31, 2010, we had 37 gross (8 net) wells in progress primarily in Arkansas and Oklahoma.

Leasehold Acreage

The following table shows our approximate developed and undeveloped (gross and net) leasehold acreage as of December 31, 2010:

	Leasehold Acreage			
	Developed		Undeveloped	
	Gross	Net	Gross	Net
Alabama	-	-	2,647	1,249
Arkansas	23,670	6,775	31,479	9,358
Louisiana	8,589	2,944	8,848	3,010
Mississippi	1,628	1,178	-	-
Oklahoma	77,242	33,439	39,143	29,294
Texas	42,422	21,981	16,020	10,156
Wyoming	640	160	14,682	3,671
Federal Waters	41,614	16,393	23,560	14,039
Total	195,805	82,870	136,379	70,777

Leases covering 23% of our net undeveloped acreage are scheduled to expire in 2011, 5% in 2012, 6% in 2013 and 66% thereafter. Of the acreage subject to leases scheduled to expire during 2011, 27% relates to undeveloped acreage in Texas and Alabama where we do not anticipate any further drilling. We expect to hold the majority of the remaining acreage scheduled to expire in 2011 through drilling.

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") 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 or Bureau of Ocean Energy Management, Regulation and Enforcement (the "BOEM") 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 gas leases, which are administered by the BOEM pursuant to the OCSLA. These leases are issued through competitive bidding and contain relatively standardized terms. These leases require compliance with detailed BOEM regulations and orders that are subject to interpretation and change by the BOEM.

For offshore operations, lessees must obtain BOEM approval for exploration, development and production plans prior to the commencement of such operations. In addition to permits required from other agencies such as the Coast Guard, the Army Corps of Engineers and the United States Environmental Protection Agency ("USEPA"), lessees must obtain a permit from the BOEM prior to the commencement of drilling. The BOEM has promulgated regulations requiring offshore production facilities located on the Outer Continental Shelf to meet stringent engineering and construction specifications. The BOEM also has regulations restricting the flaring or venting of natural gas, and prohibiting the flaring of liquid hydrocarbons and oil without prior authorization. Similarly, the BOEM has promulgated other regulations governing the plugging and abandonment of wells located offshore and the installation and removal of all production facilities.

To cover the various obligations of lessees on the Outer Continental Shelf, the BOEM generally requires that lessees have substantial net worth or post bonds or other acceptable assurances that such obligations will be met. 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 the supplemental bonding requirements of the BOEM. Under some circumstances, the BOEM may require operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect our financial condition, cash flows and results of operations.

With the reorganization of the Minerals Management Service (the "MMS"), the Office of Natural Resources Revenue ("ONRR") within the Office of the Assistant Secretary for Policy, Management and Budget ("PMB"), has replaced the MMS as the governing authority administering the collection of royalties under the terms of the OCSLA and the oil and gas leases issued under the OCSLA. The amount of royalties due is based upon the terms of the oil and gas leases as well as of the regulations promulgated by the BOEM. The BOEM regulations governing the calculation of royalties and the valuation of crude oil produced from federal leases provide that the ONRR will collect royalties based upon the market value of oil produced from federal leases. The 2005 EPA formalized the royalty in-kind program of the MMS, providing that the MMS may take royalties in-kind. Secretary of the Interior Ken Salazar announced on September 16, 2009 that BOEM would begin terminating the royalty in-kind program in an orderly transition to a more transparent and accountable royalty collection program. The BOEM subsequently announced that it was closing out the royalty in-kind program as of September 30, 2010. These regulations are amended from time to time, and the amendments can affect the amount of royalties that we are obligated to pay to the ONRR. However, we do not believe that these regulations or any future amendments will affect us in a way that materially differs from the way it affects other oil and gas producers, gatherers and marketers.

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 thereunder, 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 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. We had no control over such entities' 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 during oil and natural gas extraction or processing. NORM wastes are regulated under the RCRA framework, but 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 will 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.

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 mandate, the USEPA has commissioned a study to identify potential risks associated with hydraulic fracturing. The USEPA expects to initiate the study in 2011 and have the initial study results available by late 2012. Depending on the results of this 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 greenhouse gas 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 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. However, apart from these developments, recent judicial decisions that have allowed certain 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.

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 46,000 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 99 full-time employees as of February 10, 2011. 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 further. 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, 2010, the aggregate amount of our outstanding indebtedness, net of cash on hand, was $86.8 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.

The recent financial crisis and continuing uncertain economic conditions may have material adverse impacts on our business and financial condition that we currently cannot predict.

As widely reported, financial markets in the United States, Europe and Asia recently experienced a period of unprecedented turmoil and upheaval characterized by extreme volatility and declines in security prices, severely diminished liquidity and credit availability, inability to access capital markets, the bankruptcy, failure, collapse or sale of various financial institutions and an unprecedented level of intervention from the United States federal government and other governments. Due to the recent financial crisis and continuing uncertain economic conditions, the demand for oil and natural gas has declined, which has negatively impacted the revenues, margins and profitability of our business. In addition, the borrowing base under our bank credit facility had been reduced as a result of redeterminations due to lower oil and gas prices. Unemployment has risen while business and consumer confidence have declined.

Although we cannot predict the additional impacts on us of continuing uncertain economic conditions, they could materially adversely affect our business and financial condition. For example:

- the demand for oil and natural gas may decline due to continuing uncertain economic conditions which could negatively impact the revenues, margins and profitability of our oil and natural gas business;

- our ability to access the capital markets may be restricted at a time when we would like, or need, to raise capital for our business including for exploration and/or development of our reserves;

- the tightening of credit or lack of credit availability to our customers could adversely affect our ability to collect our trade receivables; or

- counterparties may not fulfill their delivery or purchase obligations.

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 2009, we recognized approximately $156.1 million 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 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 half 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 half 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, 2010, approximately half 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.

Changes in the regulation of offshore oil and gas exploration in the U.S. Gulf of Mexico as a result of the recent explosion and sinking of the Deepwater Horizon drilling rig in the Gulf of Mexico and the resulting oil spill could adversely affect our business.

The legislative and regulatory response to the explosion and sinking of the Deepwater Horizon drilling rig in the Gulf of Mexico and the resulting oil spill is ongoing. In 2010, the U.S. Department of the Interior issued new regulations relating to the design of wells, the testing of the integrity of wellbores, the use of drilling fluids, the functionality and testing of well control equipment, including blowout preventers, and other safety matters, and various Congressional committees began pursuing legislation to regulate drilling activities and increase liability. In January 2011, the President's National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling released its report, recommending that the federal government require additional regulation and an increase in liability caps. Although it is difficult to predict the ultimate impact of these new regulations, such regulations and any further new guidelines, regulations, legislation or other steps that the U.S. government or any other governments may implement with respect to offshore oil and gas exploration in the U.S. Gulf of Mexico could disrupt or delay our operations, increase the cost of our operations, reduce the area of our operations for drilling rigs, impose increased liability on our operations or otherwise adversely affect our operations in the U.S. Gulf of Mexico.

Federal and state legislation and regulatory initiatives relating to 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 expects to initiate the study in 2011 and have the initial study results available by late 2012.

In addition, some states have taken actions concerning hydraulic fracturing. In October 2010, the Governor of Pennsylvania issued a moratorium on new natural gas development on state forest lands. The New York Legislature passed a bill imposing a moratorium on issuance of new permits for the drilling of wells that use hydraulic fracturing for the purpose of stimulating natural gas or oil in the Marcellus Shale formation, but the Governor of New York subsequently vetoed the bill. On December 13, 2010, however, the Governor of New York issued Executive Order No. 41, which prohibits issuance of state permits for high-volume hydraulic fracturing combined with horizontal drilling until the New York Department of Environmental Conservation completes its Final Supplemental Generic Environmental Impact Statement ("SGEIS"). Under the order, the New York Department of Environmental Conservation must publish a revised draft SGEIS on or about June 1, 2011 and allow a public comment period of at least 30 days. Accordingly, this moratorium is expected to last until at least July 1, 2011. Other states could take similar action.

Several states have considered, or are considering, legislation or regulations that would require disclosure of chemicals used for hydraulic fracturing. In June 2010, the Wyoming Oil and Gas Conservation Commission passed a rule requiring disclosure of hydraulic fracturing fluid content. In November 2010, the Pennsylvania Environmental Quality Board proposed regulations that would require reporting of the chemicals used in fracturing fluids.

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, any new federal or state restrictions on hydraulic fracturing that may be imposed 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.

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, 2010, 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 timeframe. We removed approximately 6.4 Bcfe of proved undeveloped reserves in 2010 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 2010 production was approximately 4% less than amounts projected in our 2009 reserve report. We cannot assure you that these differences will not be material in the future.

Approximately 35% of our estimated proved reserves at December 31, 2010 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, 2010 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, 2010 are costless collars that are placed with the commodity trading branches of JPMorgan Chase Bank and Bank of America, both of whom participate in our bank credit facility. We cannot assure you that these or future counterparties will not become credit risks in the future. Hedging arrangements expose us to risks in some circumstances, including situations when the counterparty to the hedging contract defaults on the contractual obligations or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received. These hedging arrangements may 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 (reduced) our total oil and gas sales by approximately $17.5 million, $79.9 million and ($8.3) million during 2010, 2009 and 2008, 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 2010, the sales price of our stock ranged from a low of $4.70 per share (on February 24, 2010) to a high of $8.84 per share (on June 21, 2010). 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, 2010, we had reserved approximately 1.6 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 certificate of incorporation, bylaws and shareholder rights plan 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, bylaws and shareholder rights plan 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.

In November 2001, our board of directors adopted a shareholder rights plan, pursuant to which uncertificated preferred stock purchase rights were distributed to our stockholders at a rate of one right for each share of common stock held of record as of November 19, 2001. The rights plan is designed to enhance the board's ability to prevent an acquirer from depriving stockholders of the long-term value of their investment and to protect stockholders against attempts to acquire us by means of unfair or abusive takeover tactics. However, the existence of the rights plan may impede a takeover not supported by our board, including a takeover that may be desired by a majority of our stockholders or involving a premium over the prevailing stock price. The rights plan expires in November 2011.

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

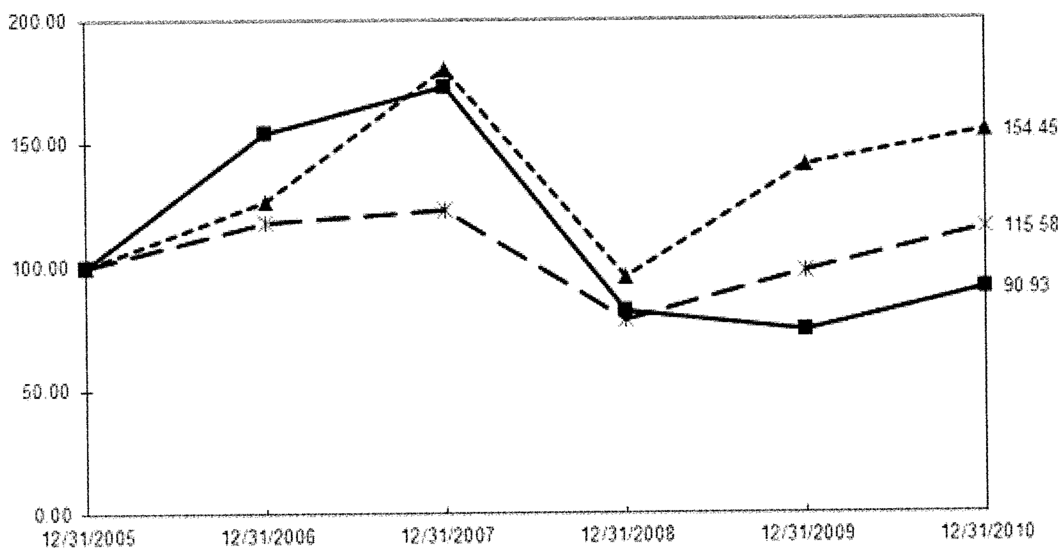
PetroQuest is involved in litigation relating to claims arising out of its operations in the normal course of business, including worker's compensation claims, tort claims and contractual disputes. Some of the existing known claims against us are covered by insurance subject to the limits of such policies and the payment of deductible amounts by us. We have accrued \$2.3 million at December 31, 2010, for possible liabilities related to pending litigation arising in the ordinary course of business. Otherwise, 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. (REMOVED AND RESERVED)

PART II

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

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, 2010.



	12/31/2005	12/31/2006	12/31/2007	12/31/2008	12/31/2009	12/31/2010
PetroQuest Energy Inc.	100.00	153.86	172.70	81.63	74.03	90.93
NYSE/AMEX Market Index (US Companies)	100.00	117.57	122.75	78.37	98.04	115.58
NYSE Stocks (SIC 1310-1319 US Companies) Crude Petroleum and Natural Gas	100.00	126.13	180.07	95.27	140.89	154.45

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
2009		
1st Quarter	$8.65	$0.61
2nd Quarter	5.90	2.14
3rd Quarter	6.52	2.64
4th Quarter	8.08	5.14
2010		
1st Quarter	$7.20	$4.70
2nd Quarter	8.84	5.01
3rd Quarter	7.29	5.15
4th Quarter	7.92	5.35

As of February 21, 2011, there were 369 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, 2010.

	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, 2010	23,401	$ 6.19	-	-
November 1 - November 30, 2010	-	-	-	-
December 1 - December 31, 2010	-	-	-	-

(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, 2010 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,				
	2010	2009 (1)	2008 (2)	2007	2006
	(in thousands except per share data)				
Revenues	$ 179,294	$ 218,875	$ 313,958	$ 262,334	$ 199,520
Net income (loss) available to common stockholders	41,987	(95,330)	(102,100)	39,245	23,986
Net income (loss) available to common stockholders per share:					
Basic	0.67	(1.72)	(2.08)	0.79	0.49
Diluted	0.66	(1.72)	(2.08)	0.78	0.49
Oil and gas properties, net	312,940	321,875	512,861	554,850	431,814
Total assets	439,517	410,459	670,249	644,347	518,290
Long-term debt	150,000	178,267	278,998	148,755	195,537
Stockholders' equity	208,162	162,105	237,487	302,317	189,711

(1) The year ended December 31, 2009 includes a ceiling test write-down of $156.1 million.
(2) The year ended December 31, 2008 includes a 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, Gulf Coast Basin, Arkansas 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, Arkansas, 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 2010, we have invested approximately $733 million into growing our longer life assets. During the seven year period ended December 31, 2010, we have realized a 94% drilling success rate on 653 gross wells drilled. Comparing 2010 metrics with those in 2003, the year we implemented our diversification strategy, we have grown production by 220% and estimated proved reserves by 131%. At December 31, 2010, 87% of our estimated proved reserves and 54% of our 2010 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 thus allowing us to utilize our cash flow from operations, combined with proceeds from an equity offering, to repay $130 million of bank debt since the end of 2008. 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.

During 2010, we refocused on the key elements of our business strategy with the goal of growing reserves and production in a fiscally prudent manner. Our 2011 capital expenditures, which include capitalized interest and overhead, are expected to range between $110 million and $120 million. In order to maintain our financial flexibility, we plan to fund our 2011 capital expenditures budget with cash flow from operations and $14 million in additional proceeds to be received in 2011 under the Woodford joint development agreement completed in May 2010 (see Liquidity and Capital Resources-Source of Capital: Joint Ventures). We expect to be able to actively manage our 2011 capital budget in the event commodity prices or the health of the global financial markets do not match our expectations.

Critical Accounting Policies and Estimates

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.

On December 29, 2008, the SEC issued a revision to Staff Accounting Bulletin 113 ("SAB 113") which established guidelines related to modernizing accounting and disclosure requirements for oil and natural gas companies. The revised disclosure requirements 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 revised rules also allow companies the option to disclose probable and possible reserves in addition to the existing requirement to disclose proved reserves. The revised 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. A significant change to the rules involves the pricing at which reserves are measured. The revised rules utilize 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 rather than year-end prices. In addition, the 12-month average will also be used to measure ceiling test impairments and to compute depreciation, depletion and amortization. The revised rules were effective for reserve estimates beginning December 31, 2009.

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.

Given the volatility of oil and gas prices, it is probable that our estimate of discounted future net cash flows from 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 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

The estimated fair values of our commodity derivative instruments are recorded in the consolidated balance sheet. At inception, all of our commodity derivative instruments represent hedges of the price of future oil and gas production. 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 or expense.

Our hedges are specifically referenced to NYMEX prices. 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, 2010, our derivative instruments were considered 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 operating information with respect to our oil and gas operations for the years ended December 31, 2010, 2009 and 2008. Our historical results are not necessarily indicative of results to be expected in future periods.

	Year Ended December 31,		
	2010	2009	2008
Production:			
Oil (Bbls)	663,302	600,124	680,571
Gas (Mcf)	24,501,540	28,065,270	27,031,801
Ngl (Mcfe)	2,469,871	2,532,822	2,676,403
Total Production (Mcfe)	30,951,223	34,198,836	33,791,630
Sales:			
Total oil sales	$ 52,715,434	$ 41,150,657	$ 66,349,344
Total gas sales	107,117,320	163,867,613	216,143,358
Total ngl sales	19,205,726	13,625,642	26,130,502
Total oil and gas sales	$ 179,038,480	$ 218,643,912	$ 308,623,204
Average sales prices:			
Oil (per Bbl)	$ 79.47	$ 68.57	$ 97.49
Gas (per Mcf)	4.37	5.84	8.00
Ngl (per Mcfe)	7.78	5.38	9.76
Per Mcfe	5.78	6.39	9.13

The above sales and average sales prices include increases (reductions) to revenue related to the settlement of gas hedges of $17,538,000, $74,333,000 and ($6,160,000) and oil hedges of $0, $5,559,000 and ($2,124,000) for the years ended December 31, 2010, 2009 and 2008, respectively.

Comparison of Results of Operations for the Years Ended December 31, 2010 and 2009

Net income (loss) available to common stockholders totaled $41,987,000 and ($95,330,000) for the years ended December 31, 2010 and 2009, respectively. The primary fluctuations were as follows:

Production Total production decreased 9% during the twelve month period ended December 31, 2010 as compared to the 2009 period. Gas production during the year ended December 31, 2010 decreased 13% from the comparable period in 2009. The decrease in gas production was primarily the result of reduced capital spending during 2009 and normal production declines in the Gulf Coast area. Because approximately 75% of our 2011 scheduled drilling program is allocated to our longer-life assets, we expect 2011 gas production to approximate 2010 as we continue to experience normal declines in the Gulf Coast area, offset by increased long-lived gas production.

Oil production during the twelve month period ended December 31, 2010 increased 11% from the 2009 period due to the restoration of production at our Ship Shoal 225 field after repairs and a recompletion following Hurricanes Katrina and Rita. In addition, our oil production rates have increased from the drilling success of our Turtle Bayou prospect in 2010 and workovers at our Ft. Trinidad field in E. Texas. With our entry into the Niobrara Shale and Eagle Ford Shale, which are both typically oil bearing formations, we expect to grow oil production during 2011 by approximately 10%.

Ngl production during the twelve month period ended December 31, 2010 decreased 2% from the 2009 period due to the general decline in Gulf Coast and Texas gas production.

Prices Including the effects of our hedges, average gas prices per Mcf for the twelve month period ended December 31, 2010 were $4.37, as compared to $5.84 for the 2009 period. Average oil prices per Bbl for the twelve months ended December 31, 2010 were $79.47, as compared to $68.57 for the 2009 period and average Ngl prices per Mcfe were $7.78 and $5.38 during 2010 and 2009, respectively. Stated on an Mcfe basis, unit prices received during the twelve months ended December 31, 2010 were 10% lower than the prices received during the comparable 2009 period.

Revenue Including the effects of hedges, oil and gas sales during the twelve months ended December 31, 2010 decreased 18% to $179,038,000, as compared to oil and gas sales of $218,644,000 during the 2009 period. The decreased revenue during 2010 was primarily the result of lower production and a decrease in hedge settlements realized during the year ended December 31, 2010.

Expenses Lease operating expenses for the year ended December 31, 2010 increased to $39,012,000 as compared to $38,541,000 during the 2009 period. Per unit lease operating expenses totaled $1.26 per Mcfe during the twelve month period ended December 31, 2010 as compared to $1.13 per Mcfe during the 2009 period. Per unit lease operating expenses increased primarily due to the overall reduction in produced volumes as well as the general increase in the costs of services and materials. Lease operating expenses in 2011 are expected to generally approximate lease operating expenses in 2010.

General and administrative expenses during the year ended December 31, 2010 totaled $21,341,000 as compared to expenses of $18,869,000 during 2009. Included in general and administrative expenses was share-based compensation expense related to ASC Topic 718, as follows (in thousands):

	Years Ended December 31, 2010	Years Ended December 31, 2009
Stock options:		
Incentive Stock Options	$ 793	$ 835
Non-Qualified Stock Options	2,081	2,024
Restricted stock	4,263	3,469
Share-based compensation	$ 7,137	$ 6,328

Approximately $455,000 of share based compensation expense during the year ended December 31, 2010 was the result of the voluntary early cancellation of certain stock options and accelerated recognition of associated compensation expense. In total, general and administrative expenses increased 13% in 2010 as compared to 2009 as a result of employee related costs including higher incentive compensation. We capitalized $11,894,000 and $9,330,000 of general and administrative costs during the twelve month periods ended December 31, 2010 and 2009, respectively. General and administrative expenses in 2011 are expected to approximate 2010 expenses.

The price of natural gas used in computing our estimated proved reserves during 2009 had a negative impact on our estimated proved reserves from certain of our longer-life properties and reduced the estimated future net cash flows from our estimated proved reserves. As a result, we recorded non-cash ceiling test write-downs of our oil and gas properties during 2009 totaling $156,134,000. No such write-down was recorded during 2010.

Depreciation, depletion and amortization ("DD&A") expense on oil and gas properties for the twelve months ended December 31, 2010 totaled $58,172,000, or $1.88 per Mcfe, as compared to $83,613,000, or $2.44 per Mcfe, during the comparable 2009 period. The decline in our DD&A per Mcfe was primarily the result of the ceiling test write-down of a substantial portion of our proved oil and gas properties during 2009 due to lower commodity prices, the impact of the Woodford Shale joint development agreement, as well as reserve additions during 2010 from our Oklahoma and Arkansas assets.

Interest expense, net of amounts capitalized on unevaluated properties, totaled $9,952,000 during the twelve months ended December 31, 2010 as compared to $12,615,000 during the 2009 period. We capitalized $7,771,000 of interest during the twelve month period ended December 31, 2010 and $8,679,000 during the 2009 period. We have reduced the outstanding borrowings under our bank credit facility from $130 million at December 31, 2008 to zero at December 31, 2010. We also retired our 10 3/8% Senior Notes due 2012 during August 2010 in connection with the issuance of our 10% Senior Notes due 2017, which we expect will result in a decrease in our cash used for interest payments during 2011.

As a result of the early retirement of our 10 3/8% Senior Notes, we incurred a loss during the third quarter of 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 10⅜% Senior Notes.

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. The gain was reduced by $775,000 of costs incurred by us directly related to the settlement. 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.

Other expense during 2010 included an accrual for potential liabilities associated with certain pending legal matters. During 2009, other expense included $5,673,000 related to payments made in connection with a drilling rig contract. Because we elected to idle this drilling rig, there were no corresponding assets to record in connection with the fixed payments required under this contract, regardless of actual rig usage. As a result, the costs were recorded as a component of other expense. This contract expired during July 2009. Other expense during 2009 also included $913,000 related to drill pipe inventory which was impaired to reflect the lower of cost or market.

Income tax expense (benefit) during the twelve months ended December 31, 2010 and 2009 totaled $1,630,000 and ($14,635,000), respectively. We typically provide for income taxes at a statutory rate of 35% adjusted for permanent differences expected to be realized, primarily statutory depletion, non-deductible stock compensation expenses and state income taxes.

As a result of the ceiling test write-downs recognized during 2008 and 2009, we have incurred a cumulative three-year loss. As a result of this cumulative loss and the impact it has on the determination of the recoverability of deferred tax assets through future earnings, we established a valuation allowance for a portion of our deferred tax assets. We reduced the valuation allowance by $20,488,000 during the year ended December 31, 2010, the impact of which is included in our effective tax rate. The valuation allowance was $3,195,000 as of December 31, 2010. Our effective tax rate in 2011 will be impacted by adjustments to the valuation allowance.

Comparison of Results of Operations for the Years Ended December 31, 2009 and 2008

Net loss available to common stockholders totaled ($95,330,000) and ($102,100,000) for the years ended December 31, 2009 and 2008, respectively. The decline in the net loss during 2009 was primarily attributable to the following:

Production Gas production during the twelve-month period ended December 31, 2009 increased 3% from the comparable period in 2008. The increase in gas production was primarily the result of a full year of production from discoveries at our Pelican Point and The Bluffs prospects in South Louisiana and increased production from our Oklahoma and Arkansas wells.

Oil production during the year ended December 31, 2009 decreased 12% from the comparable 2008 period primarily due to normal production declines at our Ship Shoal 72 and Turtle Bayou Fields which produce approximately half of our total oil production.

Ngl production during the twelve month period ended December 31, 2009 decreased 5% from the 2008 period due to the general decline in Texas gas production.

While production increased overall by 1% in 2009, we experienced declines in each quarter throughout 2009 as a result of our reduced capital expenditures.

Prices Including the effects of our hedges, average oil prices per barrel during 2009 were $68.57, as compared to $97.49 during 2008. Average gas prices per Mcf were $5.84 during 2009, as compared to $8.00 during 2008. Average Ngl prices per Mcfe were $5.38 during 2009, as compared to $9.76 during 2008. Stated on an Mcfe basis, unit prices received during 2009 were 30% lower than the prices received during 2008.

Revenue Including the $79,892,000 received from our hedges, oil and gas sales during the year ended December 31, 2009 totaled $218,644,000, a 29% decrease from oil and gas sales of $308,623,000 during 2008. The decreased revenue during 2009 was primarily the result of lower average pricing and decreased oil production.

Expenses Lease operating expenses for year ended December 31, 2009 decreased to $38,541,000 from $44,665,000 during 2008. Per unit lease operating expenses totaled $1.13 per Mcfe during 2009 as compared to $1.32 per Mcfe during 2008. The decreases in lease operating expenses were primarily due to the decline in costs of services and materials in the markets in which we operated as the demand for such materials and services weakened as a result of the decline in commodity prices and the overall condition of the oil and gas industry and the global economy.

Production taxes totaled $4,656,000 and $12,292,000 during 2009 and 2008, respectively. Production taxes decreased in 2009 for the following reasons. During the third quarter of 2009, we filed for a production tax refund in the amount of $1,144,000 at our Pelican Point prospect as the well qualified for a deep well severance tax exemption for a period of 24-months from the initial production date of May 2008. In addition, we received a production tax refund of $570,000 during the second quarter of 2009 related to certain of our horizontal wells in Oklahoma that qualify for a 48-month production tax exemption. Finally, the impact of lower commodity prices realized for the production from our Oklahoma, Arkansas and Texas properties contributed to the decline in production taxes during the 2009 period. Partially offsetting these decreases was a 15% increase in the Louisiana gas severance tax rate effective July 1, 2009.

General and administrative expenses during 2009 totaled $18,869,000 as compared to expenses of $23,249,000 during 2008. Included in general and administrative expenses was share-based compensation expense related to ASC Topic 718 as follows (in thousands):

	Years Ended December 31, 2009	Years Ended December 31, 2008
Stock options:		
Incentive Stock Options	$ 835	$ 1,316
Non-Qualified Stock Options	2,024	2,729
Restricted stock	3,469	5,537
Share based compensation	$ 6,328	$ 9,582

We capitalized $9,330,000 of general and administrative costs during the twelve-month period ended December 31, 2009 and $9,888,000 during the comparable 2008 period. The decline in general and administrative expenses during 2009 was, in part, due to lower non-cash share based compensation. In addition, during May 2008, we incurred compensation expense of approximately $2.5 million, or approximately $1.2 million net of capitalization, related to our election to pay employee taxes on the vesting of certain restricted stock grants. No similar expense was incurred during 2009.

The price of natural gas used in computing our estimated proved reserves during 2009 had a negative impact on our estimated proved reserves from certain of our longer-life properties and reduced the estimated future net cash flows from our estimated proved reserves. As a result, we recorded non-cash ceiling test write-downs of our oil and gas properties during 2009 totaling $156,134,000. See Note 11, "Ceiling Test" for further discussion of the ceiling test write-downs. By comparison, we recorded non-cash ceiling test write downs of our oil and gas properties during 2008 totaling $266,156,000.

Depreciation, depletion and amortization ("DD&A") expense on oil and gas properties for 2009 totaled $83,613,000, or $2.44 per Mcfe, as compared to $131,348,000, or $3.89 per Mcfe during 2008. The decline in our DD&A per Mcfe was the result of the ceiling test write-downs of a substantial portion of our proved oil and gas properties during 2009 and the fourth quarter of 2008 as a result of lower commodity prices.

Interest expense, net of amounts capitalized on unevaluated properties, totaled $12,615,000 during 2009 as compared to $9,327,000 during 2008. We capitalized $8,679,000 and $10,525,000 of interest during 2009 and 2008, respectively. The increase in interest expense during the year ended 2009 was due to the increase in our bank debt outstanding during the first nine months of 2009 as compared to the first nine months of 2008. During the second half of 2009, we repaid a total of $101 million of bank borrowings.

Other expense during 2009 includes $5,673,000 related to payments made in connection with a drilling rig contract. As a result of the significant decline in natural gas prices, we elected to idle this drilling rig. Because there were no corresponding assets to record in connection with the fixed payments required under the contract, regardless of actual rig usage, the costs were recorded as a component of other expense. This contract expired during July 2009. No similar expense was incurred during 2008. Other expense during 2009 also included $913,000 related to drill pipe inventory which was impaired to reflect the lower of cost or market.

Income tax benefit during 2009 totaled $14,635,000 as compared to $55,581,000 during 2008. We provided 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, we had incurred a cumulative three-year loss. As a result of this cumulative loss and the impact it had on the determination of the recoverability of deferred tax assets through future earnings, we established a valuation allowance of $23,279,000 as of December 31, 2009. The impact of this valuation allowance was included in our effective tax rate for the year ended December 31, 2009.

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, 2010, we had a working capital surplus of $59.1 million compared to a surplus of $24.7 million at December 31, 2009. The increase was primarily due to the cash received from the Woodford Shale joint development agreement and the settlement of the lawsuit discussed above.

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.

Source of Capital: Operations

Net cash flow from operations increased from $121,822,000 in 2009 to $131,644,000 during 2010. The increase in operating cash flow during 2010 was primarily attributable to the timing of payments made in 2009 to reduce our accounts payable to vendors and the cash received during the first quarter of 2010 in connection with a legal settlement. Partially offsetting these increases was an increase to our joint interest billing receivables, which is a result of the increase in drilling activity.

Source of Capital: Debt

On August 19, 2010, we issued $150 million in principal amount of 10% Senior Notes due 2017 (the "Notes") in a public offering. The net proceeds of the offering, together with cash on hand, were used to fund our tender offer and consent solicitation and redemption of our 10⅜% Senior Notes due 2012. In total, we incurred a loss of $6 million relating to the early retirement of the 10 3/8% Senior Notes. Approximately $1.8 million of the loss related to non-cash amortization of deferred financing costs and discount associated with the 10⅜% Senior Notes.

At December 31, 2010, the estimated fair value of the Notes was $154.5 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, 2010, $5.5 million had been accrued in connection with the March 1, 2011 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., Calyon New York Branch, Bank of America, N.A., Wells Fargo Bank, N.A., and Whitney National Bank. The Credit Agreement provides us with a $300 million revolving credit facility that permits borrowings based on 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. In connection with the retirement of the 10⅜% Senior Notes in August 2010, the maturity date of the credit facility was extended to October 2, 2013. As of December 31, 2010 we had no borrowings outstanding under (and no letters of credit issued pursuant to) the Credit Agreement and availability of $100 million.

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 $100 million effective September 29, 2010. The next borrowing base redetermination is scheduled to occur by March 31, 2011. 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 85% 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 1.625% to 2.625% depending on borrowing base usage) or the adjusted LIBO rate ("Eurodollar") plus a margin (based on a sliding scale of 2.5% to 3.5% depending on borrowing base usage). 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 of 0.5%.

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. As of December 31, 2010, we were in compliance with all of the covenants contained in the Credit Agreement.

Source of Capital: Issuance of Securities

On June 30, 2009, we received net proceeds of approximately $38 million through the public offering of 11.5 million shares of our common stock, which included the issuance of 1.5 million shares pursuant to the underwriters' over-allotment option.

During October 2010, a new 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, 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 million in cash at closing, net of $2.6 million in transaction fees, and will receive an additional $14 million on November 30, 2011. If certain production performance metrics are achieved, we will receive an additional $14 million during the drilling program. Additionally, WSGP will fund a share of our future drilling costs under a long-term drilling program.

The additional capital provided by this agreement allows us to accelerate the pace of our development of the Woodford Shale and pursue opportunities in other basins. We have also entered into an Eagle Ford Shale Joint Acquistion Interim Agreement and a Marcellus Shale Joint Acquisition Interim Agreement with NextEra Energy Gas Producing, LLC ("NEGP"), a subsidiary of Nextera Energy Resources, LLC, whereby NEGP will have the option to participate as a 50% partner in the leasing and development of these shale plays.

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 cannot assure you that we will be able to sell any of our assets in the future.

Use of Capital: Exploration and Development

Our 2011 capital budget, which includes capitalized interest and general and administrative costs, is expected to range between $110 million and $120 million. Because we operate the majority of our activities, we expect to be able to control the timing of a substantial portion of our capital investments. As a result, we plan to fund our 2011 capital budget with cash flow from operations and the $14 million in additional proceeds to be received in 2011 from the Woodford joint development agreement.

However, if commodity prices decline or if actual production or costs vary significantly from our expectations, our 2011 exploration and development activities could be reduced or could be financed through a combination of cash on hand or borrowings under the bank credit facility.

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. During 2010, we acquired acreage positions in the Niobrara Shale and the Eagle Ford Shale with development activities budgeted for both areas during 2011. We plan to actively pursue opportunities to expand these positions during 2011, as well as increase the scope of certain of our other assets and enter new areas. We expect to finance these 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, 2010 (in thousands):

	Total	2011	2012	2013	2014	2015	After 2015
10% senior notes (1)	$ 250,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 175,000
Operating leases (2)	3,367	1,167	1,060	376	227	216	321
Capital projects (3)	24,592	1,517	1,942	776	1,508	74	18,775
Purchase commitments (4)	11,619	11,619	-	-	-	-	-
Total	$ 289,578	$ 29,303	$ 18,002	$ 16,152	$ 16,735	$ 15,290	$ 194,096

(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 2011, a 10% decline in the estimated average prices we expect to receive for our crude oil and natural gas production would have an approximate $15.4 million impact on our 2011 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 2010, we received approximately $17.5 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 Bank of America, which 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, 2010, we had entered into the following oil and gas hedge contracts accounted for as cash flow hedges:

Production Period	Instrument Type	Daily Volumes	Weighted Average Price
Natural Gas:			
2011	Costless Collar	10,000 Mmbtu	$4.00 - 4.87
Crude Oil:			
2011	Costless Collar	250 Bbl	$80.00 - 90.10

At December 31, 2010, we recognized a liability of approximately $1.1 million related to the estimated fair value of these derivative instruments. Based on estimated future commodity prices as of December 31, 2010, we would realize a $0.7 million loss, net of taxes, as a decrease to oil and gas sales during the next 12 months. These losses are expected to be reclassified based on the schedule of oil and gas volumes stipulated in the derivative contracts.

During January, 2011, we entered into the following additional gas hedge contract accounted for as a cash flow hedge:

Production Period	Instrument Type	Daily Volumes	Weighted Average Price
Natural Gas:			
February - December 2011	Costless Collar	5,000 Mmbtu	$4.50 - 4.96

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, 2010 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, 2010. 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, 2010 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, 2010 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, 2010.

February 28, 2011

/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, 2010, 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, 2010, 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, 2010 and 2009, and the related consolidated statements of operations, cash flows, stockholders' equity and comprehensive income for each of the three years in the period ended December 31, 2010 and our report dated February 28, 2011 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

New Orleans, Louisiana
February 28, 2011

ITEM 9B. OTHER INFORMATION

NONE

PART III

ITEMS 10, 11, 12, 13 & 14

Pursuant to General Instruction G of Form 10-K, the information concerning Item 10. Directors, Executive Officers and Corporate Governance, Item 11. Executive Compensation, Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters, Item 13. Certain Relationships and Related Transactions, and Director Independence and Item 14. Principal Accounting Fees and Services, is incorporated by reference to the information set forth in the definitive Proxy Statement of PetroQuest Energy, Inc. relating to the Annual Meeting of Stockholders to be held May 12, 2011, 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-24 of this Form 10-K:

Report of Independent Registered Public Accounting Firm
Consolidated Balance Sheets as of December 31, 2010 and 2009
Consolidated Statements of Operations for the three years ended December 31, 2010
Consolidated Statements of Cash Flows for the three years ended December 31, 2010
Consolidated Statements of Stockholders' Equity for the three years ended December 31, 2010
Consolidated Statements of Comprehensive Income for the three years ended December 31, 2010
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, Stephen H. Green, Mark K. Stover, Dalton F. Smith III and J. Bond Clement) 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, Stephen H. Green, Mark K. Stover, Dalton F. Smith III and J. Bond Clement) 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 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).

10.8 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).

10.9 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).

10.10 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).

† 10.11 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).

† 10.12 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).

† 10.13 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).

† 10.14 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).

† 10.15 Amended Executive Employment Agreement dated effective as of December 31, 2008, between Stephen H. Green and PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit 10.5 to Form 8-K filed January 6, 2009).

† 10.16 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).

† 10.17 Amended Executive Employment Agreement dated effective as of December 31, 2008, between Dalton F. Smith III and PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit 10.20 to Form 10-K filed February 27, 2009).

† 10.18 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).

† 10.19 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, Stephen H. Green, Mark K. Stover, Dalton F. Smith III and J. Bond Clement (incorporated herein by reference to Exhibit 10.6 to Form 8-K filed January 6, 2009).

† 10.20 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, Stephen H. Green, Mark K. Stover, Dalton F. Smith III, J. Bond Clement, 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).

10.21 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).

10.22 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).

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, 2010, as prepared by Ryder Scott Company, L.P.

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* 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 February 28, 2011.

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 February 28, 2011.

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. Ru cks, 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, 2010 and 2009, and the related consolidated statements of operations, cash flows, stockholders' equity and comprehensive income (loss) for each of the three years in the period ended December 31, 2010. 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, 2010 and 2009, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2010, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, in 2009 the Company changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements.

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, 2010, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2011 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

New Orleans, Louisiana
February 28, 2011

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

	December 31, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents	$ 63,237	$ 20,772
Revenue receivable	13,386	16,457
Joint interest billing receivable	12,193	11,792
Other receivable	13,795	-
Hedge asset	-	2,796
Prepaid drilling costs	789	2,383
Drilling pipe inventory	11,711	19,297
Other current assets	1,827	1,619
Total current assets	116,938	75,116
Property and equipment:		
Oil and gas properties:		
Oil and gas properties, full cost method	1,433,642	1,296,177
Unevaluated oil and gas properties	54,851	108,079
Accumulated depreciation, depletion and amortization	(1,175,553)	(1,082,381)
Oil and gas properties, net	312,940	321,875
Gas gathering assets	4,177	4,848
Accumulated depreciation and amortization of gas gathering assets	(1,496)	(1,198)
Total property and equipment	315,621	325,525
Other assets, net of accumulated depreciation and amortization of $6,435 and $8,342, respectively	6,958	9,818
Total assets	$ 439,517	$ 410,459
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable to vendors	$ 26,097	$ 27,113
Advances from co-owners	7,963	3,662
Oil and gas revenue payable	7,220	7,886
Accrued interest and preferred stock dividend	6,575	3,133
Hedge liability	1,089	-
Asset retirement obligation	1,517	4,517
Other accrued liabilities	7,380	4,106
Total current liabilities	57,841	50,417
Bank debt	-	29,000
10 3/8% Senior Notes	-	149,267
10% Senior Notes	150,000	-
Asset retirement obligation	23,075	19,399
Other liabilities	439	271
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 61,565 and 61,177 shares, respectively	62	61
Paid-in capital	266,907	259,981
Accumulated other comprehensive income (loss)	(1,089)	1,768
Accumulated deficit	(57,719)	(99,706)
Total stockholders' equity	208,162	162,105
Total liabilities and stockholders' equity	$ 439,517	$ 410,459

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, 2010	2009	2008
Revenues:			
Oil and gas sales	$ 179,038	$ 218,644	$ 308,623
Gas gathering revenue	256	231	5,335
	179,294	218,875	313,958
Expenses:			
Lease operating expenses	39,012	38,541	44,665
Production taxes	4,917	4,656	12,292
Depreciation, depletion and amortization	59,326	84,772	134,340
Ceiling test writedown	-	156,134	266,156
Gas gathering costs	31	191	2,309
General and administrative	21,341	18,869	23,249
Accretion of asset retirement obligation	1,306	2,452	1,317
Interest expense	9,952	12,615	9,327
	135,885	318,230	493,655
Gain on legal settlement	12,400	-	-
Loss on early extinguishment of debt	(5,973)	-	-
Gain on sale of assets	-	485	26,812
Other income (expense)	(1,080)	(5,955)	344
Income (loss) from operations	48,756	(104,825)	(152,541)
Income tax expense (benefit)	1,630	(14,635)	(55,581)
Net income (loss)	47,126	(90,190)	(96,960)
Preferred stock dividend	5,139	5,140	5,140
Net income (loss) available to common stockholders	$ 41,987	$ (95,330)	$ (102,100)
Earnings per common share:			
Basic			
Net income (loss) per share	$ 0.67	$ (1.72)	$ (2.08)
Diluted			
Net income (loss) per share	$ 0.66	$ (1.72)	$ (2.08)
Weighted average number of common shares:			
Basic	61,415	55,363	48,971
Diluted	61,789	55,363	48,971

See accompanying Notes to Consolidated Financial Statements.

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

	Year Ended December 31, 2010	2009	2008
Cash flows from operating activities:			
Net income (loss)	$ 47,126	$ (90,190)	$ (96,960)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Deferred tax expense (benefit)	1,630	(14,635)	(55,581)
Depreciation, depletion and amortization	59,326	84,772	134,340
Ceiling test writedown	-	156,134	266,156
Non-cash gain on legal settlement	(4,164)	-	-
Loss on early extinguishment of debt	5,973	-	-
Gain on sale of assets	-	(485)	(26,812)
Accretion of asset retirement obligation	1,306	2,452	1,317
Pipe inventory impairment	-	913	-
Share-based compensation expense	7,137	6,328	9,582
Amortization costs and other	1,334	1,512	1,492
Payments to settle asset retirement obligations	(6,274)	(1,803)	(19,377)
Changes in working capital accounts:			
Revenue receivable	3,071	3,617	2,746
Joint interest billing receivable	(401)	11,937	(1,323)
Prepaid drilling and pipe costs	9,180	14,828	(35,973)
Accounts payable and accrued liabilities	3,368	(51,375)	(4,567)
Advances from co-owners	4,301	(1,687)	(7,521)
Other	(1,269)	(496)	1,542
Net cash provided by operating activities	131,644	121,822	169,061
Cash flows from investing activities:			
Investment in oil and gas properties	(103,926)	(63,420)	(325,936)
Investment in gas gathering assets	-	(204)	(6,204)
Proceeds from sale of gathering assets, net of expenses	-	-	43,170
Proceeds from sale of unevaluated properties	22,473	-	-
Proceeds from sale of oil and gas properties and other	35,000	7,451	2,256
Net cash used in investing activities	(46,453)	(56,173)	(286,714)
Cash flows from financing activities:			
Net proceeds from (payments for) share based compensation	(210)	(366)	1,597
Deferred financing costs	(12)	(114)	(1,450)
Proceeds from common stock offering	-	38,036	-
Costs of common stock offering	-	(258)	-
Payment of preferred stock dividend	(5,137)	(5,139)	(5,439)
Repayment of bank borrowings	(29,000)	(101,000)	(128,000)
Proceeds from bank borrowings	-	-	258,000
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	(42,726)	(68,841)	124,708
Net increase (decrease) in cash and cash equivalents	42,465	(3,192)	7,055
Cash and cash equivalents at beginning of period	20,772	23,964	16,909
Cash and cash equivalents at end of period	$ 63,237	$ 20,772	$ 23,964
Supplemental disclosure of cash flow information			
Cash paid during the period for:			
Interest	$ 11,195	$ 20,335	$ 17,851
Income taxes	$ 192	$ 227	$ -

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)	Retained Earnings (Deficit)	Total Stockholders' Equity
December 31, 2007	$ 48	$ 1	$ 204,979	$ (435)	$ 97,724	$ 302,317
Options exercised	1	-	1,896	-	-	1,897
Retirement of shares upon vesting of restricted stock	-	-	(300)	-	-	(300)
Share-based compensation expense	-	-	9,582	-	-	9,582
Non-cash compensation	-	-	96	-	-	96
Derivative fair value adjustment, net of tax	-	-	-	25,995	-	25,995
Preferred stock dividend	-	-	-	-	(5,140)	(5,140)
Net loss	-	-	-	-	(96,960)	(96,960)
December 31, 2008	$ 49	$ 1	$ 216,253	$ 25,560	$ (4,376)	$ 237,487
Options exercised	-	-	65	-	-	65
Retirement of shares upon vesting of restricted stock	-	-	(431)	-	-	(431)
Issuance of common stock	12	-	37,766	-	-	37,778
Share-based compensation expense	-	-	6,328	-	-	6,328
Derivative fair value adjustment, net of tax	-	-	-	(23,792)	-	(23,792)
Preferred stock dividend	-	-	-	-	(5,140)	(5,140)
Net loss	-	-	-	-	(90,190)	(90,190)
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

See accompanying Notes to Consolidated Financial Statements.

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

	Year Ended December 31,		
	2010	2009	2008
Net income (loss)	$ 47,126	$ (90,190)	$ (96,960)
Change in fair value of derivative instruments, accounted for as hedges, net of tax benefit (expense) of $1,028, $13,983 and ($15,267), respectively	(2,857)	(23,792)	25,995
Comprehensive income (loss)	$ 44,269	$ (113,982)	$ (70,965)

See accompanying Notes to Consolidated Financial Statements.

Note 1 - Organization and Summary of Significant Accounting Policies

PetroQuest Energy, Inc. (a Delaware Corporation) ("PetroQuest" or the "Company") 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, Arkansas, 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 the Company and its subsidiaries, PetroQuest Energy, L.L.C., PetroQuest Oil & Gas, L.L.C, Pittrans, Inc. and TDC Energy LLC. All intercompany accounts and transactions have been eliminated.

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.

Reserve Estimates and Oil and Gas Properties

On December 29, 2008, the SEC adopted revised rules related to modernizing accounting and disclosure requirements for oil and natural gas companies. The revised disclosure requirements 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 revised rules also allow companies the option to disclose probable and possible reserves in addition to the existing requirement to disclose proved reserves. The revised 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. A significant change to the rules involves the pricing at which reserves are measured. The revised rules utilize 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 rather than year-end prices. In addition, the 12-month average will also be used to measure ceiling test impairments and to compute depreciation, depletion and amortization. The revised rules were effective for reserve estimates beginning December 31, 2009.

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, which 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.

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 costs are evaluated and proved reserves established or 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 cash flow from proved reserves based on first of the month average twelve-month oil and gas 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.

Gas Gathering Assets

During 2005, the Company acquired interests in several gas gathering systems used in the transportation of natural gas. The costs related to these systems are depreciated on a straight line basis over their estimated remaining useful lives, generally 14 years. During 2008, the Company sold the majority of its gas gathering assets located in Oklahoma for net proceeds of $43.2 million and recorded a $26.8 million gain.

Other Assets

Other assets includes furniture and fixtures (net of accumulated depreciation), which are depreciated over their useful lives ranging from 3-7 years, and deferred financing costs, which are amortized over the life of the related debt.

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 and Other Accrued Liabilities

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, 2010 and 2009, the Company had $0.6 million recorded related to an allowance for doubtful accounts. Other accrued liabilities at December 31, 2010 and 2009 included $6.3 million and $3.5 million, respectively, related to accrued incentive compensation costs.

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. At December 31, 2010, the pipe inventory that the Company has available for sale had a value of $0.5 million, which reflects the lower of cost or market.

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.

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, 2010 and 2009 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,		
	2010	2009	2008
Shell Trading Co.	19%	17%	(a)
Texon LP	17%	17%	23%
Laclede Energy	17%	12%	11%
Gary Williams	10%	(a)	(a)
Atmos Energy	(a)	13%	(a)
Louis Dreyfus Corporation	(a)	(a)	11%
Crosstex	(a)	(a)	11%
DCP Midstream	(a)	(a)	10%

(a) Less than 10 percent

Fair Value of Financial Instruments

The fair value of cash and cash equivalents, accounts receivable and accounts payable approximates book value at December 31, 2010 and 2009 due to the short-term nature of these accounts. Hedging instruments are reflected as a liability on the balance sheet at an estimated fair value of approximately \$1.1 million at December 31, 2010 and as an asset at an estimated fair value of approximately \$2.8 million at December 31, 2009, as required under ASC Topic 815. The estimated fair value of the 10% senior notes due 2017 (the "Notes") at December 31, 2010 was \$154.5 million, as compared to the book value of \$150 million. At December 31, 2009, the fair value of the 10 3/8% senior notes due 2012 (the "10 3/8 Notes") was \$150 million, while the book value of the 10 3/8% Notes, net of discount, was \$149.3 million. The estimated fair value of the Notes was provided by independent brokers using the actual year-end market quotes for the Notes.

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 cash flow 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. All of the Company's derivative instruments qualified for cash flow hedge accounting during 2010, 2009 and 2008. As a result, the changes in fair value of these instruments were recorded to other comprehensive income (loss). The cash settlements of cash flow hedges are recorded as adjustments to oil and gas sales. Oil and gas revenues include additions (reductions) related to the net settlement of hedges totaling \$17,538,000, \$79,892,000 and (\$8,284,000) during 2010, 2009 and 2008, respectively. Instruments not qualifying for hedge accounting treatment are recorded on the balance sheet at fair value and changes in fair value are recognized in earnings as derivative expense (income).

The Company's hedges are specifically referenced to NYMEX prices. 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, 2010, the Company's hedging contracts were considered effective cash flow hedges. See Note 8 for further discussion of the Company's derivative instruments.

Note 2 - Convertible Preferred Stock

During 2007, the Company completed the public offering of 1,495,000 shares of its 6.875% Series B cumulative convertible perpetual preferred stock (the "Series B Preferred Stock").

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

Dividends. The Series B Preferred Stock will accumulate dividends at an annual rate of 6.875% for each share of Series B Preferred Stock. Dividends will be 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 will pay dividends in cash, every quarter.

Mandatory conversion. After October 20, 2010, 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 - Common Stock Offering

On June 30, 2009, the Company received $38 million in net proceeds through the public offering of 11.5 million shares of its common stock, which included the issuance of 1.5 million shares pursuant to the underwriters' over-allotment option.

Note 4 – Woodford Joint Development Agreement

In May 2010, PetroQuest Energy, L.L.C. 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 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. The Company recorded a receivable of approximately $14 million, included in other receivable in the balance sheet, related to additional proceeds to be received on November 30, 2011, which represents a non-cash investing activity for purposes of the Statement of Cash Flows. The Company recorded the total consideration of approximately $71 million as an adjustment to capitalized costs with no gain or loss recognized. If certain production performance metrics are achieved, the Company will receive an additional $14 million during the drilling program. Additionally, WSGP will fund a share of the Company's future drilling costs under a long-term drilling program.

Note 5 – Earnings Per Share

Effective January 1, 2009, the Company adopted the provisions of ASC Topic 260-10-45. As a result of adoption, the Company's earnings per share for 2010 and 2009 have been calculated in accordance with ASC Topic 260-10-45 and the Company retrospectively adjusted the calculation of earnings per share for the 2008 period. The previously reported basic and diluted loss per share for 2008 was $2.08.

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

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

For the Year Ended December 31, 2009	Loss (Numerator)	Shares (Denominator)	Per Share Amount
Net loss available to common stockholders	$ (95,330)	55,363	$ (1.72)
Effect of dilutive securities:			
Stock options	-	-	
Restricted stock	-	-	
Series B preferred stock	-	-	
DILUTED EPS	$ (95,330)	55,363	$ (1.72)

For the Year Ended December 31, 2008	Loss (Numerator)	Shares (Denominator)	Per Share Amount
Net loss available to common stockholders	$ (102,100)	48,971	$ (2.08)
Effect of dilutive securities:			
Stock options	-	-	
Restricted stock	-	-	
Series B preferred stock	-	-	
DILUTED EPS	$ (102,100)	48,971	$ (2.08)

Common shares issuable upon the assumed conversion of the Series B preferred stock totaling 5,148,000 shares during 2010, 2009 and 2008 were not included in the computation of diluted earnings per share because the inclusion would have been anti-dilutive. No restricted stock or stock options were included in the computation of diluted earnings per share for the years ended December 31, 2009 or 2008, respectively, because the inclusion would have been anti-dilutive as a result of the net loss reported for the periods. Options to purchase 1.7 million shares of common stock were outstanding during the year ended December 31, 2010 and were not included in the computation of diluted earnings per share because the options' exercise prices were in excess of the average market price of the common shares.

Note 6 – Share Based Compensation

The Company accounts for share-based compensation in accordance with ASC Topic 718. Share-based compensation expense is reflected as a component of the Company's general and administrative expense. A detail of share-based compensation for the years ended December 31, 2010, 2009 and 2008 is as follows (in thousands):

	Years Ended December 31,		
	2010	2009	2008
Stock options:			
Incentive Stock Options	$ 793	$ 835	$ 1,316
Non-Qualified Stock Options	2,081	2,024	2,729
Restricted stock	4,263	3,469	5,537
Share-based compensation	$ 7,137	$ 6,328	$ 9,582

During the years ended December 31, 2010, 2009 and 2008, the Company recorded income tax benefits of approximately $2.4 million, $2 million and $3.1 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, 2010, the Company had $5.1 million of unrecognized compensation cost related to granted restricted stock and stock options. This amount will be recognized as an expense over a weighted average period of approximately two years.

Stock Options

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

The Company computes the fair value of its stock options using the Black-Scholes option-pricing model assuming a stock option forfeiture rate and expected term based on historical activity and expected volatility computed using historical stock price fluctuations on a weekly basis for a period of time equal to the expected term of the option. 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 2010, 2009 and 2008:

	Years Ended December 31,		
	2010	2009	2008
Dividend yield	0%	0%	0%
Expected volatility	78.2% - 80.3%	75.5% - 78.4%	54.9% - 69.8%
Risk-free rate	1.5% - 3.0%	2.3% - 2.5%	1.7% - 3.6%
Expected term	6 years	6 years	6 years
Forfeiture rate	5.0%	5.0%	5.0%
Stock options granted (1)	69,500	638,486	563,900
Wgtd. avg. grant date fair value per share	$ 4.21	$ 4.77	$ 9.45
Fair value of grants (1)	$ 293,000	$ 3,045,000	$ 5,330,000

(1) Prior to applying estimated forfeiture rate

The following table details stock option activity during the year ended December 31, 2010:

	Number of Options	Wgtd. Avg. Exercise Price	Wgtd. Avg. Remaining Life	Aggregate Intrinsic Value (000's)
Outstanding at beginning of year	3,126,758	$8.91		
Granted	69,500	6.08		
Expired/cancelled/forfeited (1)	(1,440,707)	13.67		
Exercised	(130,000)	2.51		
Outstanding at end of year	1,625,551	5.09	5.7 years	$3,914
Options exercisable at end of year	1,121,400	$4.29	4.3 years	$3,601
Options expected to vest	478,943	6.87	8.6 years	$297

(1) During 2010, 1,438,782 stock options having a weighted average exercise price of $13.69 were voluntarily cancelled by certain employees and directors.

The intrinsic value of options exercised during 2010 and 2008 totaled approximately $0.5 million and $9 million, respectively. The intrinsic value of options exercised during 2009 was immaterial.

The following table summarizes information regarding stock options outstanding at December 31, 2010:

Range of Exercise Price	Options Outstanding 12/31/10	Wgtd. Avg. Remaining Contractual Life	Wgtd. Avg. Exercise Price	Options Exercisable 12/31/10	Wgtd. Avg. Exercise Price
$1.53 - $3.17	523,167	2.9 years	$2.93	523,167	$2.93
$3.17 - $4.88	260,065	4.0 years	$3.57	233,400	$3.42
$4.88 - $6.72	218,833	5.7 years	$5.91	145,333	$5.84
$6.72 - $13.44	623,486	8.7 years	$7.25	219,500	$7.44
	1,625,551	5.7 years	$5.09	1,121,400	$4.29

Restricted Stock

The Company computes the fair value of its service based restricted stock using the closing price of the Company's stock at the date of grant, and compensation expense is recognized assuming a 5% estimated forfeiture rate. Restricted stock granted to employees generally vests 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. 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. Periodically, the Company adjusts compensation expense based on the difference between actual and estimated forfeitures.

The following table details restricted stock activity during 2010:

	Number of Shares	Wgtd. Avg. Fair Value per Share
Outstanding at beginning of year	1,446,267	$7.58
Granted	590,207	5.44
Expired/cancelled/forfeited	(44,850)	7.17
Lapse of restrictions	(352,815)	7.42
Outstanding at December 31, 2010 (1)	1,638,809	$6.86

(1) At December 31, 2010, the weighted average remaining life of restricted stock outstanding was 3 years and the intrinsic value of restricted stock outstanding, using the closing stock price on December 31, 2010, was $12.3 million.

Note 7 – Asset Retirement Obligations

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 summarizes the changes to the Company's asset retirement obligation liability (in thousands):

	Years Ended December 31,	
	2010	2009
Asset retirement obligation, beginning of period	$ 23,916	$ 25,633
Liabilities incurred	275	58
Liabilities settled	(7,362)	(1,803)
Accretion expense	1,306	2,452
Revisions in estimates	6,457	(2,424)
Asset retirement obligation, end of period	24,592	23,916
Less: current portion of asset retirement obligation	(1,517)	(4,517)
Long-term asset retirement obligation	$ 23,075	$ 19,399

Liabilities settled during 2010 included two offshore fields that were completely decommissioned and the liability for an additional offshore platform in the amount of $1.1 million that was transferred to a third party related to a farmout, which represents a non-cash investing activity for purposes of the Statement of Cash Flows. Revisions in estimates during 2010 primarily represent increased cost estimates to decommission the Company's offshore fields and plug and abandonment the related wells.

Note 8 – Derivatives

As of December 31, 2010, the Company had entered into the following oil and natural gas contracts accounted for as cash flow hedges:

Production Period	Instrument Type	Daily Volumes	Weighted Average Price
Natural Gas:			
2011	Costless Collar	10,000 Mmbtu	$4.00 - 4.87
Crude Oil:			
2011	Costless Collar	250 Bbl	$80.00 - 90.10

At December 31, 2010, the Company had a liability of $1.1 million related to the estimated fair value of these derivative instruments. Based on estimated future commodity prices as of December 31, 2010, the Company would realize a $0.7 million loss, net of taxes, as a decrease to gas sales during the next 12 months. These losses are expected to be reclassified based on the schedule of oil and gas volumes stipulated in the derivative contracts.

Oil and gas sales include additions (reductions) related to the settlement of gas hedges of $17,538,000, $74,333,000 and ($6,160,000) and oil hedges of zero, $5,559,000 and ($2,124,000) for the years ended December 31, 2010, 2009 and 2008, respectively.

During January, 2011, we entered into the following additional gas hedge contract accounted for as a cash flow hedge:

Production Period	Instrument Type	Daily Volumes	Weighted Average Price
Natural Gas:			
February - December 2011	Costless Collar	5,000 Mmbtu	$4.50 - 4.96

All of the Company's derivative instruments at December 31, 2010, 2009 and 2008 were designated as hedging instruments under ASC Topic 815. The following tables reflect the fair value of the Company's derivative instruments in the consolidated financial statements as of and for the years ended 2010, 2009 and 2008 (in thousands):

Effect of Derivative Instruments on the Consolidated Balance Sheet at December 31, 2010 and 2009:

	Commodity Derivatives	
Period	Balance Sheet Location	Fair Value
December 31, 2010	Hedging liability	$ (1,089)
December 31, 2009	Hedging asset	$ 2,796

Effect of Derivative Instruments on the Consolidated Statement of Operations for the twelve months ended December 31, 2010, 2009 and 2008:

	Commodity Derivatives		
Period	Amount of Gain (Loss) Recognized in Other Comprehensive Income (Loss)	Location of Gain (Loss) Reclassified into Income	Amount of Gain (Loss) Reclassified into Income
December 31, 2010	$ (2,857)	Oil and gas sales	$ 17,538
December 31, 2009	$ (23,792)	Oil and gas sales	$ 79,892
December 31, 2008	$ 25,995	Oil and gas sales	$ (8,284)

As defined in ASC Topic 820, fair value is 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. ASC Topic 820 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.

With the adoption of ASC Topic 820, the Company classified its commodity derivatives based upon the data used to determine fair value. The Company's derivative instruments at December 31, 2010 were in the form of costless collars based on NYMEX pricing. 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 valuation of the Company's derivatives subject to fair value measurement on a recurring basis as of December 31, 2010 and 2009 (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 - 2010	-	$ (1,089)	-
Commodity Derivatives - 2009	-	$ 2,796	-

Note 9 – Long-Term Debt

On August 19, 2010, PetroQuest Energy, Inc. issued $150 million in principal amount of 10% Senior Notes due 2017 (the "Notes") in a public offering. The net proceeds of the offering, together with cash on hand, were used to fund the tender offer and consent solicitation and redemption of the Company's 10⅜% Senior Notes due 2012. The Company incurred a loss totaling $6 million relating to the early retirement of the 10⅜% Senior Notes. Approximately $1.8 million of the loss related to non-cash amortization of deferred financing costs and discount associated with the 10⅜% Senior Notes.

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, 2010, $5.5 million had been accrued in connection with the March 1, 2011 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., Calyon New York Branch, Bank of America, N.A., Wells Fargo Bank, N.A., and Whitney National Bank. The Credit Agreement provides the Company with a $300 million revolving credit facility that permits borrowings based on 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. In connection with the retirement of the 10⅜% Senior Notes in August 2010, the maturity date of the Credit Agreement was automatically extended to October 2, 2013. As of December 31, 2010 the Company had no borrowings outstanding under (and no letters of credit issued pursuant to) the Credit Agreement and availability of $100 million.

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. The current borrowing base is $100 million effective September 29, 2010. The next borrowing base redetermination is scheduled to occur by March 31, 2011. 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 85% 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 1.625% to 2.625% depending on borrowing base usage) or the adjusted LIBO rate ("Eurodollar") plus a margin (based on a sliding scale of 2.5% to 3.5% depending on borrowing base usage). 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 of 0.5%.

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. As of December 31, 2010, 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 2010, 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 $103,000, $520,000 and $261,000 and with respect to Mr. Nordberg, costs billed exceeded revenues disbursed in the amount of $100. During 2009, in their capacities as working interest owners or overriding royalty interest owners, revenues, net of costs, were disbursed to Messrs. Goodson, Green, Stover and Nordberg, or their affiliates, in the amounts of $218,000, $559,000, $64,000 and $7,000 and with respect to Mr. Rucks, costs in the amount of $43,000 were billed with no revenue disbursed. During 2008, in their capacities as working interest owners or overriding royalty interest owners, revenues, net of costs, were disbursed to Messrs. Goodson, Green, Stover and Nordberg, or their affiliates, in the amounts of $2,876,000, $1,206,000, $249,000 and $4,000, respectively. 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 substantially all of the gross revenue received by him in 2010.

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, 2010, the Company's joint interest billing receivable included approximately $17,000 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, 2010.

Periodically, the Company charters private aircraft for business purposes. During 2010, 2009 and 2008, the Company paid approximately $169,400, $13,500 and $6,700, 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 or any other aircraft arrangement.

Note 11 – Ceiling Test

The Company uses the full cost method to account for its oil and natural gas operations. Accordingly, the costs to acquire, explore for and develop oil and natural gas properties are capitalized. Capitalized costs of oil and gas properties, net of accumulated DD&A and related deferred taxes, are limited to the estimated future net cash flows from proved oil and gas reserves, including the effects of cash flow hedges in place, discounted at 10%, plus the lower of cost or fair value of unproved properties, as adjusted for related income tax effects (the full cost ceiling). If capitalized costs exceed the full cost ceiling, the excess is charged to ceiling test write down of oil and gas properties in the quarter in which the excess occurs. The Company recorded $156.1 million and $266.2 million of ceiling test write-downs during 2009 and 2008, 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 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, 2010	2009	2008
Acquisition costs:			
Proved	$ 10,421	$ 427	$ 3,014
Unproved	11,310	1,592	58,826
Divestitures - unproved (1)	(36,139)	-	-
Exploration costs:			
Proved	34,310	16,495	149,811
Unproved	10,384	3,249	6,048
Development costs	34,286	19,333	118,891
Capitalized general and administrative and interest costs	19,665	18,009	21,181
Total costs incurred	$ 84,237	$ 59,105	$ 357,771

	For the Year-Ended December 31, 2010	2009	2008
Accumulated depreciation, depletion and amortization (DD&A)			
Balance, beginning of year	$ (1,082,381)	$ (832,290)	$ (432,530)
Provision for DD&A	(58,172)	(83,613)	(131,348)
Ceiling test writedown	-	(156,134)	(266,156)
Sale of proved properties and other (1)	(35,000)	(10,344)	(2,256)
Balance, end of year	$ (1,175,553)	$ (1,082,381)	$ (832,290)
DD&A per Mcfe	$ 1.88	$ 2.44	$ 3.89

(1) During 2010, the Company recorded $71 million in consideration from its Woodford joint development agreement (See Note 4).

At December 31, 2010 and 2009, unevaluated oil and gas properties totaled $54,851,000 and $108,079,000, respectively, and were not subject to depletion. Unevaluated costs at December 31, 2010 included $10,384,000 of costs related to 28 exploratory wells in progress at year-end. These costs will be transferred to evaluated oil and gas properties during 2011 upon the completion of drilling. At December 31, 2009, unevaluated costs included $3,249,000 related to exploratory wells in progress. All of these costs were transferred to evaluated oil and gas properties during 2010. The Company capitalized $7,771,000, $8,679,000 and $10,525,000 of interest during 2010, 2009 and 2008, respectively. Of the total unevaluated oil and gas property costs of $54,851,000 at December 31, 2010, $22,282,000 or 40%, was incurred in 2010, $6,938,000, or 13%, was incurred in 2009 and $25,631,000 or 47% was incurred in prior years. The Company expects that the majority of the unevaluated costs at December 31, 2010 will be evaluated within the next three years, including $19,231,000 that the Company expects to be evaluated during 2011.

Note 13 - Income Taxes

The Company follows the provisions of ASC Topic 740 which provides for recognition of deferred tax assets and liabilities for deductible temporary timing differences, operating loss carryforwards, statutory depletion carryforwards and tax credit carryforwards, net of a valuation allowance for any asset for which it is more likely than not will not be realized in the Company's tax return. As a result of the ceiling test write-downs realized during 2009 and 2008, the Company has 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, 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 with respect to a portion of its deferred tax assets. The valuation allowance was $3.2 million and $23.3 million as of December 31, 2010 and 2009, respectively.

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

	December 31, 2010	2009
Net operating loss carryforwards	$ 4,737	$ 6,697
Percentage depletion carryforward	3,596	3,344
Alternative minimum tax credit	776	201
Contributions carryforward and other	90	65
Temporary differences:		
Oil and gas properties - full cost	(10,141)	8,803
Hedges	405	(1,040)
Share-based compensation	3,732	5,209
Valuation allowance	(3,195)	(23,279)
Deferred tax liability	$ -	$ -

At December 31, 2010, the Company had approximately $24,014,000 of operating loss carryforwards, of which $11,280,000 relates to excess tax benefits with respect to share-based compensation that have not been recognized. If not utilized, approximately $4,550,000 of such carryforwards would expire in 2023 and the remainder would completely expire by the year 2026. The Company has available for tax reporting purposes $10,274,000 in statutory depletion deductions that may be carried forward indefinitely.

Income tax expense (benefit) for each of the years ended December 31, 2010, 2009 and 2008 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, 2010	2009	2008
Amount computed using the statutory rate	$ 17,065	$ (36,689)	$ (53,389)
Increase (reduction) in taxes resulting from:			
State & local taxes	1,073	(2,306)	(3,357)
Percentage depletion carryforward	(252)	(725)	310
Allowance for alternative minimum tax	575	-	-
Non-deductible stock option expense (1)	295	311	490
Share-based compensation (2)	3,041	1,334	-
Other	321	161	365
Change in valuation allowance	(20,488)	23,279	-
Income tax expense (benefit)	$ 1,630	$ (14,635)	$ (55,581)

(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. However, at December 31, 2010 the Company had accrued $2.25 million in connection with estimated liabilities related to certain legal matters.

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 9.1 Bcf of natural gas per year 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, 2010 under these operating leases are as follows (in thousands):

2011	$	1,167
2012		1,060
2013		376
2014		227
2015		216
Thereafter		321
	$	3,367

Total rent expense under operating leases was approximately $1,090,000, $1,082,000 and $965,000 in 2010, 2009 and 2008, respectively.

Note 15 - Oil and Gas Reserve Information - Unaudited

The Company's net proved oil and gas reserves at December 31, 2010 have been estimated by independent petroleum engineers in accordance with guidelines established by the Securities and Exchange Commission.

The 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. 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.

On December 29, 2008, the SEC issued a revision to Staff Accounting Bulletin 113 ("SAB 113") which established guidelines related to modernizing accounting and disclosure requirements for oil and natural gas companies. The revised disclosure requirements 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 revised rules also allow companies the option to disclose probable and possible reserves in addition to the existing requirement to disclose proved reserves. The revised 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. A significant change to the rules involves the pricing at which reserves are measured. The revised rules utilize a historical 12-month average price based on 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 rather than year-end prices. In addition, the 12-month average will also be used to measure ceiling test impairments and to compute depreciation, depletion and amortization. The revised rules are effective for reserve estimates beginning December 31, 2009.

During 2010, the Company's estimated proved reserves increased by 8%. This increase was primarily due to successful drilling programs in Oklahoma in the Woodford Shale and in Arkansas in the Fayetteville Shale. Additionally, reserves increased due to positive performance and price revisions from the Company's Oklahoma and Arkansas assets. Partially offsetting these increases was the sale of approximately 29 Bcfe of Woodford Shale PUDs to WSGP (See Note 4). In total, the Company added approximately 30 Bcfe of proved reserves in Oklahoma during 2010. Overall, the Company had a 97% drilling success rate during 2010 on 102 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) and gas 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, 2007	2,342	13,314	129,154	156,520
Revisions of previous estimates	(21)	1,453	(12,579)	(11,252)
Extensions, discoveries and other additions	499	1,314	68,486	72,794
Purchase of producing properties	62	-	1,047	1,419
Sale of reserves in place	-	-	(295)	(295)
Production	(681)	(2,676)	(27,032)	(33,794)
Proved reserves as of December 31, 2008	2,201	13,405	158,781	185,392
Revisions of previous estimates	321	(664)	(9,953)	(8,691)
Extensions, discoveries and other additions	9	300	39,003	39,357
Sale of reserves in place	-	-	(2,913)	(2,913)
Production	(600)	(2,533)	(28,065)	(34,198)
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
Proved developed reserves				
As of December 31, 2008	2,030	9,326	114,691	136,197
As of December 31, 2009	1,775	7,134	93,294	111,078
As of December 31, 2010	1,474	6,078	110,599	125,521

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 the FASB. 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, 2010	2009	2008
Future cash flows	$ 810,131	$ 614,293	$ 889,732
Future production costs	(223,175)	(193,427)	(275,117)
Future development costs	(144,451)	(148,595)	(148,167)
Future income taxes	(41,156)	(3,166)	(14,479)
Future net cash flows	401,349	269,105	451,969
10% annual discount	(164,974)	(94,817)	(137,182)
Standardized measure of discounted future net cash flows	$ 236,375	$ 174,288	$ 314,787

Changes in Standardized Measure	Year Ended December 31, 2010	2009	2008
Standarized measure at beginning of year	$ 174,288	$ 314,787	$ 447,258
Sales and transfers of oil and gas produced, net of production costs	(117,572)	(95,555)	(259,950)
Changes in price, net of future production costs	93,702	(100,150)	(172,214)
Extensions and discoveries, net of future production and development costs	42,028	2,790	147,089
Changes in estimated future development costs, net of development costs incurred during this period	5,803	38,407	36,567
Revisions of quantity estimates	46,373	(15,045)	(25,037)
Accretion of discount	17,700	32,719	54,065
Net change in income taxes	(16,568)	9,698	80,988
Purchase of reserves in place	1,478	-	1,944
Sale of reserves in place	(798)	(2,138)	(1,378)
Changes in production rates (timing) and other	(10,059)	(11,225)	5,455
Standardized measure at end of year	$ 236,375	$ 174,288	$ 314,787

The weighted average prices of oil, Ngls and gas used for the above tables at December 31, 2010, 2009 and 2008 were $79.72, $60.57 and $41.53 per barrel of oil, respectively, $7.00, $4.89 and $4.15 per Mcfe of natural gas liquids, respectively, and $3.56, $2.84 and $4.68 per Mcf of natural gas, respectively.

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
2010:				
Revenues	$ 47,614	$ 41,918	$ 46,285	$ 43,477
Income from operations	27,106	9,046	6,525	6,079
Net income available to common stockholders	29,717	5,248	4,939	2,083
Earnings per share:				
Basic	$ 0.47	$ 0.08	$ 0.08	$ 0.03
Diluted	$ 0.46	$ 0.08	$ 0.08	$ 0.03
2009:				
Revenues	$ 59,449	$ 55,261	$ 50,254	$ 53,911
Income (loss) from operations (1)	(100,476)	17,184	13,616	(35,149)
Net income (loss) available to common stockholders (1)	(66,957)	7,746	4,453	(40,572)
Earnings (loss) per share:				
Basic	$ (1.36)	$ 0.15	$ 0.07	$ (0.66)
Diluted	$ (1.36)	$ 0.15	$ 0.07	$ (0.66)

(1) Loss from operations and net loss available to common stockholders reported during the three months ended March 31 and December 31, 2009 include non-cash ceiling test write-downs of $103.5 million and $52.6 million, respectively.

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the Registration Statements (Form S-3 Nos. 333-169973, 333-124746, 333-42520 and 333-89961 and Form S-8 Nos. 333-151296, 333-134161, 333-102758, 333-88846, 333-67578, 333-52700 and 333-65401) of PetroQuest Energy, Inc. and in the related Prospectuses of our reports dated February 28, 2011, with respect to the consolidated financial statements of PetroQuest Energy, Inc. and the effectiveness of internal control over financial reporting of PetroQuest Energy, Inc., included in this Annual Report (Form 10-K) for the year ended December 31, 2010.

/s/Ernst & Young LLP

New Orleans, Louisiana
February 28, 2011

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE REGISTERED ENGINEERING FIRM F-1580
1100 LOUISIANA SUITE 3800 HOUSTON, TEXAS 77002-5235
FAX (713) 651-0849
TELEPHONE (713) 651-9191

Exhibit 23.2

CONSENT OF RYDER SCOTT COMPANY, L.P.

We hereby consent to (i) the inclusion of our reserve report relating to certain estimated quantities of the proved reserves of oil and gas, future net income and discounted future net income, effective December 31, 2010 of PetroQuest Energy, Inc. (the "Company") in this Annual Report on Form 10-K prepared by the Company for the year ending December 31, 2010, filed as Exhibit 99.1 of the Form 10-K, and (ii) the incorporation by reference in this Annual Report on Form 10-K prepared by the Company for the year ending December 31, 2010, and to the incorporation by reference thereof into the Company's previously filed Registration Statements on Form S-3 (File Nos. 333-169973, 333-124746, 333-42520 and 333-89961) and Form S-8 (File Nos. 333-151296, 333-134161, 333-102758, 333-88846, 333-67578, 333-52700 and 333-65401), of information contained in our report relating to certain estimated quantities of the Company's proved reserves of oil and gas, future net income and discounted future net income, effective December 31, 2010. We further consent to references to our firm under the headings "Business - Oil and Gas Reserves" and "Risk Factors," and included in or made a part of the Annual Report on Form 10-K prepared by the Company for the year ended December 31, 2010.

We further wish to advise that we are not employed on a contingent basis and that at the time of the preparation of our report, as well as at present, neither Ryder Scott Company, L.P. nor any of its employees had, or now has, a substantial interest in PetroQuest Energy, Inc. or any of its subsidiaries, as a holder of its securities, promoter, underwriter, voting trustee, director, officer or employee.

\s\ Ryder Scott Company, L.P.

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

Houston, Texas
February 23, 2011

EXHIBIT 31.1

I, Charles T. Goodson, certify that:

1. I have reviewed this Form 10-K of PetroQuest Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Charles T. Goodson

Charles T. Goodson
Chief Executive Officer
February 28, 2011

EXHIBIT 31.2

I, J. Bond Clement, certify that:

1. I have reviewed this Form 10-K of PetroQuest Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

__/s/ J. Bond Clement__
J. Bond Clement
Chief Financial Officer
February 28, 2011

Exhibit 32.1

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of PetroQuest Energy, Inc. (the "Company") on Form 10-K for the year ending December 31, 2010 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, Charles T. Goodson, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that:

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

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

/s/Charles T. Goodson
Charles T. Goodson
Chief Executive Officer
February 28, 2011

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of PetroQuest Energy, Inc. (the "Company") on Form 10-K for the year ending December 31, 2010 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, J. Bond Clement, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that:

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

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

/s/ J. Bond Clement
J. Bond Clement
Chief Financial Officer
February 28, 2011

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

CORPORATE INFORMATION

Board of Directors
Charles T. Goodson
Chairman of the Board,
Chief Executive Officer, and President
PetroQuest Energy, Inc.

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

Mark K. Stover
Executive Vice President
Exploration and Development

Stephen H. Green
Senior Vice President
Exploration

Dalton F. Smith III
Senior Vice President
Business Development

Mark K. Bastelle
Vice President - Oklahoma Assets

Corporate Address
PetroQuest Energy, Inc.
400 East Kaliste Saloom Road, Suite 6000
Lafayette, Louisiana 70508
Telephone: (337) 232-7028
Fax: (337) 232-0044
Web: www.petroquest.com

Exploration Offices
450 Gears Road, Suite 330
Houston, Texas 77067
Telephone: (713) 784-8300
Fax: (713) 784-8327

1717 S. Boulder, Suite 201
Tulsa, Oklahoma 74119
Telephone: (918) 582-2770
Fax: (918) 582-2778

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

Independent Auditors
Ernst & Young LLP
New Orleans, Louisiana 70170

Legal Counsel
Porter & Hedges, LLP
Houston, Texas 77002

Onebane Law Firm
Lafayette, Louisiana 70502

Annual Meeting
The Company's Annual Meeting of Stockholders will be held at 9:00 A.M. CDT on May 12, 2011, 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


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