PetroQuest Energy, Inc.

2008 Annual Report

Corporate Profile

PetroQuest Energy seeks to deliver value to its stockholders by focusing on maintaining a stable reserve and production base with the majority of proved reserves located in lower-risk, repeatable resource trends. The Company continues its transition from a pure Gulf Coast operator to a diversified resource company and plans to emphasize using free cash flow to build liquidity and strengthen its balance sheet during this period of market uncertainty. PetroQuest has diversified its asset base over the past few years and has substantially lowered its geologic risk profile as a result. We believe the stability built by prioritizing operations in longer-life basins positions us to weather current market conditions in 2009 and ultimately return to our overall growth strategy once the current commodity and economic downturn ends.

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Front Cover Photo:
Woodford rig drilling the
Tom Bell Memorial Well.

The Annual Meeting will be held at 9:00 a.m. CDT on May 13, 2009, at the City Club at River Ranch, 221 Elysian Fields Drive, Lafayette, LA 70508.

	2003 Annual	2004 Annual	2005 Annual	2006 Annual	2007 Annual	2008 Q1	2008 Q2	2008 Q3	2008 Q4	2008 Annual	5-Year CAGR
Production											
Natural Gas, MMcf	5,193	9,305	12,058	21,528	24,966	6,728	7,381	7,214	8,385	29,708	42%
Crude Oil, MBbl	745	818	665	695	1,080	194	173	138	176	681	NM
Natural Gas, MMcfe	9,660	14,216	16,051	25,697	31,444	7,890	8,417	8,042	9,442	33,792	28%
Financial ($ Thousands, except per share amounts)											
Total Revenues	$ 47,910	$ 84,595	$ 120,552	$ 199,520	$ 262,334	$ 76,550	$ 92,868	$ 78,276	$ 66,264	$ 313,958	46%
Net Income (Loss)	3,640	16,348	21,417	23,986	40,619	15,444	23,060	18,045	(153,509)	(96,960)	NM
Preferred Stock Dividends	--	--	--	--	1,374	1,283	1,285	1,287	1,285	5,140	NM
Net Income (Loss) Available to Common Stockholders	$ 3,640	$ 16,348	$ 21,417	$ 23,986	$ 39,245	$ 14,161	$ 21,775	$ 16,758	$ (154,794)	$ (102,100)	NM
Per Common Share:											
Basic	$ 0.08	$ 0.37	$ 0.46	$ 0.50	$ 0.82	$ 0.29	$ 0.45	$ 0.34	$ (3.14)	$ (2.08)	NM
Diluted	$ 0.08	$ 0.35	$ 0.44	$ 0.49	$ 0.79	$ 0.28	$ 0.41	$ 0.32	$ (3.14)	$ (2.08)	NM

Financial and Operational Highlights

Year-Over-Year Review	2003	2004	2005	2006	2007	2008	5-Year CAGR
Reserves							
Natural Gas, MMcf	57,793	79,069	109,115	118,153	142,468	172,186	24%
Crude Oil, MBbl	4,245	3,714	3,642	2,731	2,342	2,201	NM
Natural Gas, MMcfe	83,263	101,353	130,967	134,539	156,520	185,392	17%
Percent Developed	67%	68%	69%	72%	69%	73%	
Percent Natural Gas	69%	78%	83%	88%	91%	93%	
Percent Offshore	55%	59%	39%	30%	29%	32%	
Future Undiscounted Net Cash Flows, $000s	$ 293,349	$ 443,487	$ 861,689	$ 516,013	$ 779,395	$ 466,449	10%
SEC PV-10, Before Taxes, $000s	$ 214,365	$ 326,267	$ 639,734	$ 384,313	$ 540,651	$ 327,193	9%
Commodity Prices							
PetroQuest Realized, Natural Gas, $/Mcf	$ 5.14	$ 5.99	$ 7.47	$ 7.04	$ 7.21	$ 8.16	
Henry Hub Cash Market Average, Natural Gas, $/Mcf	5.49	6.15	8.89	6.73	6.97	8.89	Source: Bloomberg
PetroQuest Realized, Crude Oil, $/Bbl	28.47	35.31	45.76	60.91	70.52	97.49	
WTI (Cushing) Spot Average, Crude Oil, $/Bbl	31.06	41.48	56.59	66.09	72.23	99.92	Source: Bloomberg
PetroQuest Realized Natural Gas Equivalent, $/Mcfe	4.96	5.95	7.51	7.54	8.15	9.13	
Statistics							
Reserve Replacement, Excluding Revisions, %	384%	220%	337%	152%	132%	220%	
6-Year Reserve Replacement, Excluding Revisions, %						213%	
Finding & Development Costs, Excluding Revisions, $/Mcfe	$ 1.43	$ 2.77	$ 3.62	$ 4.36	$ 5.82	$ 4.82	
6-Year Finding & Development Costs, Excluding Revisions, $/Mcfe						$ 3.97	
Per Unit Analysis, $/Mcfe							
Total Revenues	$ 4.96	$ 5.95	$ 7.51	$ 7.76	$ 8.34	$ 9.29	13%
Lease Operating Expense and Production Taxes	1.07	1.04	1.54	1.61	1.27	1.69	10%
Gas Gathering Costs	--	--	0.08	0.14	0.13	0.07	NM
Gross Operating Margin	3.89	4.91	5.89	6.01	6.94	7.54	14%
Interest Expense	0.06	0.20	0.77	0.56	0.43	0.28	36%
General and Administrative	0.46	0.44	0.46	0.59	0.67	0.69	8%
Preferred Stock Dividends	--	--	--	--	0.04	0.15	NM
Gross Cash Margin	$ 3.37	$ 4.27	$ 4.66	$ 4.86	$ 5.80	$ 6.42	14%

Letter to Stockholders

PetroQuest Energy is a natural gas company with a history of delivering reserve growth, stable production, and attractive returns for stockholders.

Before I delve into our results and views of 2008 and 2009, this is a very appropriate time to contrast and compare 2008 and 2007. In many respects, 2008 was a great year for PetroQuest Energy despite the poor economic climate. We achieved company record drilling and production results, and our fiscal conservatism contributed to our achieving many of our 2008 goals. These solid operating results were overshadowed by low year-end oil and natural gas prices that are persisting into 2009. Although we reduced our 2009 capital budget by 74% compared to 2008, we believe we can still maintain production or even achieve modest production growth.

It is an understatement to say that 2008 was a year of extreme volatility. As crude oil prices rose to record levels, so too did the associated costs to drill and complete our wells. By the end of 2008, drilling activity was curtailed across the entire industry, a reflection of the dramatic drop in both crude oil and natural gas prices. I can remember as a child hearing my Father talk about just how quickly the industry can go from boom to bust and back to boom. Are we in a bust-cycle? I don't believe we're going to relive 1986, the worst year I've experienced, and the very year PetroQuest Energy was founded. Rather, I believe our past and future success is borne from applying what we have learned to the challenges of the present. Those lessons serve as the guiding principles that we adhere to today.

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 so that we can manage our own pace of growth, rather than having someone else manage it for us; and**
- **Stay focused on the long-term pursuit of opportunities.**

I am particularly proud of how well our people have executed our strategies in the face of adversity, challenges and rapid change. I expect we will reap benefits when product prices improve, as I expect they will. In 2008, we added lease holdings, continued investing in geologic and seismic data, and built a large and diverse inventory of well locations. In 2009, we are well prepared to put our collective shoulders into expanding PetroQuest's reserves and production when commodity prices improve and costs stabilize.

...our past and future success is borne from applying what we have learned to the challenges of the present.

Our 4,900 drilling locations are expected to deliver future visible growth.

2008 In Perspective

Historic World Events

2008 was a remarkable year for our industry, country and world. The year began against the backdrop of steadily increasing oil prices, reflecting continuing expansion of the global economy and its ever-present need for a steady, secure supply of energy.

In retrospect, it is difficult to believe oil declined 61% during the latter half of the year from a record high of $147 per barrel in July 2008. Natural gas prices followed suit, with Henry Hub prices peaking at nearly $13/MMBtu in June 2008, mirroring general trends in global crude markets as industrial demand remained robust through the summer months. Economic conditions in the U.S. reflected general optimism that growth experienced since the last major recession would continue, even if there were quiet concerns about the sustainability of oil and natural gas prices. As late as August 2008, the consensus within our industry was that natural gas would remain in the $7 to $9/MMBtu range well into 2009.

The U.S. Presidential election cycle added to the drama of the unfolding financial crisis, compounding anxieties over monetary policy with inherent uncertainties associated with closely fought national elections. Our industry was caught to some degree in the convergence of these events, as the debate raged over sending billions of dollars overseas for foreign oil, how we might begin to lessen our dependence on overseas energy sources, and whether renewable energy represents a viable alternative to fossil fuels within certain economic sectors. Federal bailout packages were hurried through the legislative process, various high visibility national plans were developed and advocated within the private sector to address the foreign oil dependence issue, and ultimately the demand destruction created during the high price environment in the summer months took its toll, as both oil and natural gas prices declined drastically by the end of the year.

To compound these incredible events, back to back major hurricanes struck the Louisiana coast, shutting in a significant percentage of Gulf of Mexico oil and natural gas production. To put it mildly, 2008 was a challenging year for our industry. But through conservative operational management and our ability to keep costs under control, we believe we are in a position to take advantage of the markets moving forward.

Focus on Strategic Goals

As 2008 began, we were executing our strategic plan to deliver accelerated growth through our commitment to an extensively planned drilling program.

This remains our long-range strategic plan, even during the challenging market conditions prevalent as 2009 begins. We think we are uniquely positioned to focus on building liquidity through our stable production base, while retaining the flexibility to return to the growth theme when better market conditions return. For our stockholders, this means the strength of

Ultimately, the world will continue to consume energy, and the Energy Information Administration continues to project increasing long-term consumption of oil and natural gas both globally and in the U.S.

our organization, the quality of our resource plays, the dedication of our people and our ability to deliver results, which we believe will allow us to survive and thrive while the economic storm rages around us. Just as the keel of a ship provides strength and stability in stormy seas, the foundation upon which PetroQuest is built enables us to weather the storm and emerge ready to return to our long-term strategy of growth. Ultimately, the world will continue to consume energy, and the Energy Information Administration continues to project increasing long-term consumption of oil and natural gas both globally and in the U.S. As the saying goes: "Oil and Gas. It always comes back."

Overcoming Challenges

We are intent on managing our balance sheet and prudently managing our debt.

While PetroQuest was in the midst of re-negotiating its credit facility within the negative financial environment associated with the collapse of the capital markets in October 2008, we kept the faith that our past performance and superior asset base would serve us well. The once-in-a-lifetime set of circumstances that either imploded several financial institutions or brought them to the brink of complete elimination would give extreme cause for concern to any company trying to re-negotiate an existing financial obligation. However, not only were we successful in closing the transaction, we expanded our bank group from three to five and increased our borrowing base. We also extended the maturity date from November 2009 to February 2012, which is particularly significant given there are many economic predictions that the current recession will last into 2010. The fact that we were able to increase our borrowing base and diversify our banking group is a testament to the strength of the company overall, recognition of our diversification strategy across resource plays, and a vote of confidence in the team we have assembled to execute our strategic plan. It is also further recognition of our 2008 reserve growth.

The two other significant challenges we overcame this year were both natural events: Hurricanes Gustav and Ike. These back-to-back hurricanes resulted in the shut-in of 96% of Gulf of Mexico oil and 73% of Gulf of Mexico natural gas, and resulted in the State of Louisiana declaring disasters in 34 parishes. As recently as January 14, 2009, the Minerals Management Service estimated that 11% of Gulf oil production and 15% of Gulf natural gas production remains shut-in as a result of the two storms. Hurricane Ike was the third most destructive hurricane ever to make landfall in the United States and had a significant impact in Louisiana.

Needless to say, both storms had great impact on offshore production, and we deferred approximately 2 Bcf equivalent of third and fourth quarter production as a result of the storms. However, our Gulf Coast team worked tirelessly to restore our production, and as I write this letter, approximately 1% of our production remains shut-in. This further demonstrates our sense of teamwork and shared purpose at PetroQuest. We have what I believe is one of the strongest technical and operational teams in the industry, which allowed us to respond quickly when hurricanes adversely affected our operations.

Delivering Results

Despite all the headwinds in the form of market turmoil, global economic uncertainty, and industrial demand challenges, PetroQuest still delivered company-record results in 2008.

Considering how difficult 2008 was, I think PetroQuest employees should all be particularly proud that we were able to deliver results for our stockholders, while many energy companies are fighting for survival.

We ended 2008 with 185.4 Bcfe of proved reserves, a new company record. About 68% of our reserves are located in longer-lived basins, 93% are natural gas, and 73% of our proved reserves are categorized as proved developed. These are important points – we have the cleanest burning energy product to sell in the U.S., we have an inventory of more than 4,900 drilling locations that we expect will deliver future visible growth, and we have a very dependable production base to pay for that growth.

The Securities and Exchange Commission (SEC) issued new regulations for disclosing the quantity and value of a company's total proved crude oil and natural gas reserves. On December 29, 2008, the SEC "unanimously approved revisions to modernize its oil and gas company reporting requirements to help investors evaluate the value of their investments in these companies." The new disclosures are effective December 31, 2009.

A key change in modernizing the SEC regulations allows companies to use average commodity prices throughout the year to calculate the value of proved reserves versus the current method of using year-end prices.

Using the new SEC pricing guidelines, PetroQuest's total proved reserves at December 31, 2008 would have been 209.8 Bcfe with a pre-tax PV-10 value of $742.2 million. These values are based on the average benchmark NYMEX prices for 2008 of $8.89 per MMBtu and $102.07 per barrel. PetroQuest used year-end 2008 benchmark NYMEX prices of $5.71 per MMBtu and $44.60 per barrel.

PetroQuest's oil and gas revenues in 2008 were $309 million, an increase of 20%, which represents a new company performance record set during one of the most challenging operating environments in recent memory.

Our total 2008 production was 33.8 Bcfe, which was a 7% increase over 2007. Approximately 47% of our production was from our longer-lived, lower-risk, repeatable resource plays. We achieved a company milestone in June 2008 when our daily production surpassed 100 MMcfe per day.

PetroQuest's Woodford program continued to accelerate in 2008, and our Tulsa team is performing very well in growing this key Company asset. We increased our Woodford leasehold position approximately 20,000 net acres and now have approximately 48,000 acres in the trend. We also expanded our production while maintaining our acreage position of approximately 18,000 acres in the Fayetteville play. Notably, we set a company record by drilling a well in the Woodford which produced at an initial production rate of 12.5 MMcf per day.

We have the technical know-how to exploit our large Woodford acreage position. In a low-price environment like we are seeing now, it is the incremental improvements from existing technologies that extract the targeted value with each turn of the bit. These existing technologies can be deployed quickly and economically, keeping a steady pace of development. We believe that keeping acreage costs low and utilizing the best existing technologies will deliver the best returns.

PetroQuest's Woodford program continued to accelerate in 2008.

Natural gas from shale resources will contribute to national energy security.

Outlook for the Future

Three years ago, I wrote to stockholders about volatility offering opportunities.

Clearly, we have been in a period of profound volatility in the energy sector, and this may be something which continues for the foreseeable future. I believe now, as I did three years ago, that this means opportunities abound. While world governments and markets struggle first to comprehend, and then to react to regular pronouncements of economic calamity, I can assure employees and stockholders that PetroQuest's priorities will be to continue controlling what we can control, operating responsibly, and prudently managing our way through 2009 by remaining flexible enough to continue delivering value in challenging circumstances.

I think the U.S. natural gas industry is poised to experience a level of national importance over the next five to ten years as our country grapples with the issues of energy security, reconstitution of our transportation infrastructure, and how we begin to measurably reduce our dependence on imported oil. Indications of this trend are the emerging and highly publicized marketing campaigns undertaken during the recent election cycle, which advocated the diversification of the nation's energy supply to include increasing reliance on renewables such as wind and solar power. In addition, the President's New Energy for America Plan will promote the responsible domestic production of oil and natural gas. Obviously the devil is in the details, but my point is that our industry is positioned to provide a stable, reliable source of domestically-produced natural gas for both power generation and as a viable alternative transportation fuel. Regardless of how the macro scenarios develop, the bottom line is that natural gas prices will inevitably be impacted by the number of rigs presently being laid down in North America, and we believe PetroQuest stockholders are well-positioned to recognize the upside of this price correction.

I believe natural gas can be a bridge to an alternative energy future. U.S. natural gas is plentiful and relatively inexpensive, as non-conventional U.S. natural gas sources are continuing to grow. Natural gas production for the lower 48 states grew 3% from 2006-2007, and 8% from 2007-2008. These were the first increases after nine years of no net growth in U.S. natural gas production. This highlights two things: first, we have a stable domestic supply of natural gas, and, second, our industry is positioned to increase production to meet increasing domestic natural gas demand. We believe this bodes well for PetroQuest Energy.

2009 – Continuation of Growth and Success

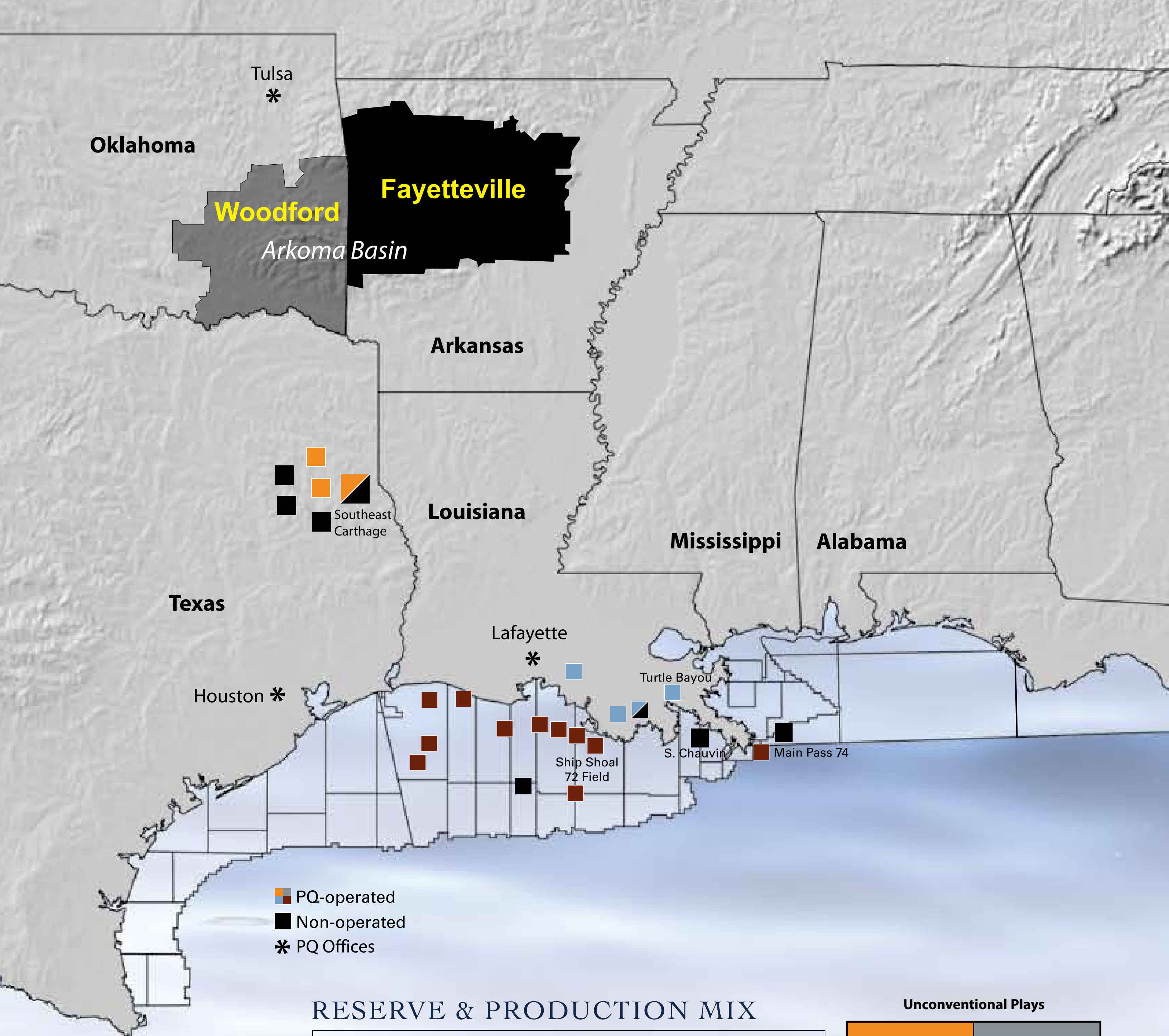
How will we get there?

First, we expect to fund drilling from cash flow in 2009. This is a simple statement to make, often more difficult to achieve. However, PetroQuest has a proven track record of drilling within cash flow dating to 2003, so drilling below cash flow is an operational benchmark we believe we can meet. Over the past five years, our drilling capital expenditures have totaled $765 million, and our cash flow has totaled $752 million.* Drilling within cash flow is not new to us, as we have been 98% funded with cash flow since 2003. We expect to manage our operations below cash flow next year and still project we will maintain or grow production in 2009 based on our planned 2009 capital expenditure program of $80 to $100 million, which represents a drilling plan of 70 to 90 wells.

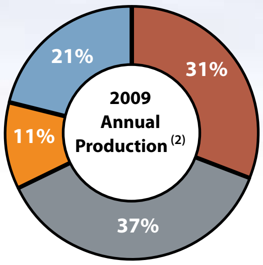
Second, we will target conservative leverage ratios. As mentioned earlier, we have no debt maturing until 2012, and we are comfortable with the leverage ratios we have in place.

We are confident in the strength of our banking group and believe our operations, balance sheet, and ability to operate within cash flow, ensure a successful 2009. The Company's capital budget

* *Calculated cash flow includes the 2008 gathering system divestiture.*

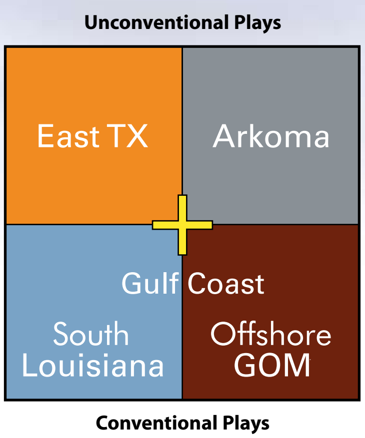


RESERVE & PRODUCTION MIX



	Proved Reserves (1)	Net Unrisked Inventory (1)	Drilling Locations (1)
East Texas	41.8	274	252
Arkoma	83.9	1,136	4,681
South Louisiana	22.6	61	11
Offshore Gulf of Mexico	37.0	133	14

(1) As of December 31, 2008 (reserves and inventory in Bcfe)
(2) Based on guidance for 2009 (90 MMcfe/day – 100 MMcfe/day)



Both our past and future success is built on a foundation of operational focus and fiscal conservatism.

for 2009 is approximately $80 to $100 million, including capitalized overhead and interest. Our primary focus for 2009 is to keep capital expenditures below internally generated cash flow.

Third, we expect to continue to generate high cash margins from our Gulf Coast assets. We have multiple high impact wells planned for the future, with working interest ownership ranging from 24% to 35%, and we expect our Gulf Coast properties will continue to generate attractive cash flows which we will use to fund capital investment. This is significant in that it allows us to remain flexible, shifting our capital spending as commodity prices warrant. Few other companies have this flexibility. A note about our hedging position – we have approximately 60% of our forecasted 2009 production hedged with an average floor of $7.64 per MMBtu and $100 per barrel.

Fourth, we operate the majority of our properties and therefore control our own destiny. We expect to drill to maintain our leases, positioning the Company to increase our activity once service costs decrease more in line with commodity prices. We expect this cost trend to develop as 2009 unfolds.

Summary

While 2009 may be a difficult year for the energy industry along with the global economy, our outlook is optimistic, and I remain as excited about PetroQuest's future as I was when I first wrote to you in our 1999 annual report. I can assure stockholders that as the macroeconomic winds continue blowing around all of us, we at PetroQuest Energy remain vigilant and focused on operating our company responsibly to deliver value as we manage growth during these tempestuous times. We believe we are well-capitalized and can manage operations self-sufficiently within cash flow. We believe we have a high quality asset base, demonstrated success in growing production and reserves, and attractive prospects for future growth. The most important contributor to our success, particularly during difficult times, is our people. I am continually amazed at the dedication and determination of our employees during good times and bad. My priority during 2009 is to deliver stockholder value and grow the company, but I remain equally committed to our employees, upon whom the success of the Company depends. While there will be as yet unseen challenges to face this year, I am confident PetroQuest will continue to deliver value and results to stockholders during the challenging year ahead.

Best regards,
Charles T. Goodson
Chairman, President and Chief Executive Officer
February 16, 2009

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, 2008
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 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):
[X] Large accelerated filer [ ] Accelerated filer [ ] Non-accelerated filer [ ] Smaller reporting company

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

The aggregate market value of the voting common equity held by non-affiliates of the registrant was approximately $1,080,871,000 as of June 30, 2008 (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 24, 2009 the registrant had outstanding 50,420,916 shares of Common Stock, par value $.001 per share.

Document incorporated by reference: Proxy Statement of PetroQuest Energy, Inc. relating to the Annual Meeting of Stockholders to be held on May 13, 2009, which is 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:

- our ability to find oil and natural gas reserves that are economically recoverable;
- the volatility of oil and natural gas prices and the significant price decline since June 30, 2008;
- the decline in the values of our properties that have resulted from ceiling test write-downs and may in the future result in additional ceiling test write-downs;
- the deteriorating economic conditions in the United States and globally;
- our ability to replace reserves and sustain production;
- our estimate of the sufficiency of our existing capital sources;
- our ability to raise additional capital to fund cash requirements for future operations;
- the uncertainties involved in estimating quantities of proved oil and natural gas reserves, in prospect development and property acquisitions or dispositions and in projecting future rates of production;
- the timing of development expenditures and drilling of wells and;
- hurricanes and other natural disasters, and the operating hazards attendant to the oil and gas business.

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. Before you invest in our common stock, 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 43.

PART I

ITEM 1. BUSINESS

Overview

PetroQuest Energy, Inc. is an independent oil and gas company incorporated in the State of Delaware with operations in Oklahoma, Texas, Arkansas and the Gulf Coast Basin. 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. For the fifth consecutive year, we achieved annual company records for production and estimated proved reserves. During 2008, we increased these metrics by approximately 7% and 18%, respectively, from the levels achieved during 2007. Prior to 2008, we had achieved four consecutive years of record net income. As a result of the significant decline in oil and gas prices during the second half of 2008, we recorded $266.2 million in ceiling test write-downs during 2008. Excluding the non-cash ceiling test write-downs, we would have realized another record year of net income during 2008.

Our results over the last five years reflect our consistent drilling success and correlate directly with the implementation of our asset diversification strategy in 2003. 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. During the five year period ended December 31, 2008, we have realized a 92% drilling success rate on 469 gross wells drilled. Comparing 2008 results with those in 2003, the year we implemented our diversification strategy, we have grown production by 250% and proved reserves by 123%.

Utilizing the cash flow generated by our higher margin Gulf Coast Basin assets, we have accelerated our penetration into longer life basins in Oklahoma, Arkansas and Texas through significantly increased and successful drilling activity and selective acquisitions. Specific asset diversification activities include the 2003 acquisition of proved reserves and acreage in the Southeast Carthage Field in East Texas. In 2004, we entered the Arkoma Basin in Oklahoma by building an acreage position, drilling wells and acquiring proved reserves. During 2005 and 2006, we acquired additional acreage in Oklahoma and Texas, initiated an expanded drilling program in these areas, opened an exploration office in Tulsa, Oklahoma and divested several mature, high-cost Gulf of Mexico fields. During 2007, we acquired a leasehold position in Arkansas and continued to robustly drill in Oklahoma and Texas. During 2008, we significantly increased our acreage position in Oklahoma and increased the pace of drilling operations in our longer life basins as we invested approximately $260.4 million in Oklahoma, Arkansas and Texas, which represented 73% of our total 2008 capital expenditures.

Business Strategy

Maintain Our Financial Flexibility. During 2009, we plan to fund our drilling expenditures with cash flow from operations. In response to the impact that the decline in commodity prices has had on our cash flow, and the deteriorated condition of the financial markets caused by the global financial crisis, our 2009 capital expenditures will be significantly reduced as compared to 2008. Because we operate the majority of our proved reserves, we expect to be able to control the timing of a substantial portion of our capital investments. As a result of this flexibility, we plan to actively manage our 2009 capital budget to stay within our projected cash flow from operations, with a goal of strengthening our balance sheet, based upon commodity prices, production rates and capital costs. In addition to funding capital expenditures with cash flow from operations, during 2009 we plan to also maintain an active commodity hedging program and, as we did during 2008 and 2006, we may opportunistically dispose of non-core or mature assets to reduce debt or to provide capital for higher potential exploration and development properties that fit our long-term growth strategy.

Concentrate in Core Operating Areas and Build Scale. We plan to continue focusing our operations in Oklahoma, Arkansas, Texas and the Gulf Coast Basin. However, as a result of the decline in commodity prices and our intention to finance our capital expenditures with cash flow from operations, we expect to significantly reduce our leasing and acquisition activities during 2009. Operating in concentrated areas helps us to better control our overhead by enabling us to manage a greater amount of acreage with fewer employees and minimize incremental costs of increased drilling and production. We have substantial geological and reservoir data, operating experience and partner relationships in these regions. We believe that these factors, 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.

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 and exploitation activities and higher risk and higher impact exploration activities. While our reduced 2009 capital expenditure budget, combined with lower commodity prices, is expected to impact our near-term growth outlook, we plan to allocate our capital investments in a manner that continues to geographically and operationally diversify our asset base. Through our portfolio diversification efforts, at December 31, 2008, approximately 68% of our estimated proved reserves were located in longer life and lower risk basins in Oklahoma, Arkansas and Texas and 32% were located in the shorter life, but higher flow rate reservoirs in the Gulf Coast Basin. This compares to 61% and 52% of our proved reserves located in longer life basins at December 31, 2007 and 2006, respectively. We will continue to seek opportunities to increase our longer life onshore reserves while maintaining some exposure to shorter life, but potentially higher impact Gulf Coast reserves with a goal of having longer life reserves represent approximately 75% of our total estimated proved reserves. In terms of production diversification, during 2008, 47% of our production was derived from longer life basins versus 27% and 29% in 2007 and 2006, respectively. Our goal is to increase our production from our longer life basins to 50% of our total production.

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, exploitation and development activities. We also strive to retain operating control of the majority of our properties to control costs and timing of expenditures. At December 31, 2008, we operated 68% of our total estimated proved reserves and managed the drilling and completion activities on an additional 20% of such reserves. In addition, 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.

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.

2008 Financial and Operational Summary

During 2008, we invested $357.8 million in exploratory, development and acquisition activities as we drilled 109 gross exploratory wells and 41 gross development wells realizing an overall success rate of 96%. These activities were financed through our cash flow from operating activities, borrowings under our bank credit facility and proceeds received from the sale of the majority of our Oklahoma gas gathering assets.

The decline in oil and gas prices since June 30, 2008 had a negative impact on certain of our estimated proved reserves and related estimated net cash flows. As a result, we recorded $266.2 million in ceiling test write-downs during 2008. Offsetting the impact of declining prices on our 2008 revenues was our 7% increase in production during 2008 to a Company record 33.8 Bcfe. In total, oil and gas revenues increased by 20% during 2008.

Our estimated proved reserves at December 31, 2008 increased 18% from 2007 totaling 2,201 MBbls of oil and 172,186 MMcfe of natural gas, with a pre-tax present value, discounted at 10%, of the estimated future net revenues based on constant prices in effect at year-end ("discounted cash flow") of $327.2 million. At December 31, 2008, our standardized measure of discounted cash flows, which includes the estimated impact of future income taxes, totaled $314.8 million (see Note 13 to our financial statements). Our standardized measure of discounted cash flows at December 31, 2008 was 30% below 2007 as we utilized year-end pricing of $41.53 per barrel and $4.64 per Mcfe in 2008, compared to $96.83 per barrel and $6.52 per Mcfe at December 31, 2007.

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 2008, we expanded our evaluation of the Woodford Shale as we drilled 35 gross wells, achieving a 100% success rate. In total, we invested $157 million during 2008 in acquiring prospective Woodford Shale acreage and drilling and completing wells. As a result of our success in targeting the Woodford Shale, average daily production from our Oklahoma properties during 2008 increased to 25.1 MMcfe, a 110% increase from our 2007 average daily production. In addition to growing production, our 2008 drilling program also resulted in a 47% increase in proved reserves from our Oklahoma properties.

Arkansas

During the second and third quarters of 2007, we closed several transactions acquiring a leasehold position in Arkansas. During late 2007, we began participating in an aggressive drilling program on this acreage targeting the Fayetteville Shale. This drilling program continued during 2008 as we participated in 91 gross wells, all of which were successful. In total we invested $35.9 million in Arkansas during 2008. At December 31, 2007 we had no production and minimal proved reserves from our Arkansas assets. As a result of our 2008 investments, we grew production to an average of 4.5 MMcfe per day in 2008 and added approximately 15 Bcfe of proved reserves, net of production.

Texas

During 2008, we invested $67.5 million on the successful drilling of 10 gross wells on our Texas properties. Net production from our Texas assets averaged 14 MMcfe per day during 2008, a 23% increase from 2007 average daily production.

Gulf Coast Basin

During 2008, we drilled 7 wells onshore south Louisiana, four of which were successful, including discoveries at our Pelican Point and Leghorn prospects. Production from these two wells during 2008 provided approximately 3% of our total production.

Markets and Customers

We sell our natural gas and oil production under fixed or floating market contracts. Customers purchase all of our natural gas and oil production at current market prices. The terms of the arrangement 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.

No assurance can be given that we will be able to market all of the oil or natural gas we produce or that favorable prices can be obtained for the oil and natural gas we produce.

In view of the many uncertainties affecting the supply and demand for oil, natural gas and refined petroleum products, we are unable to predict future oil and natural gas prices and demand or the overall effect such prices and demand will have on the Company. During 2008, one customer accounted for 23%, three accounted for 11% each and one accounted for 10% of our oil and natural gas revenue. During 2007, we had three customers who accounted for 32%, 16% and 12% of our oil and natural gas revenue, respectively. For the year ended December 31, 2006, we had four customers who accounted for 22%, 14%, 12% and 11% of our oil and natural gas revenue, respectively. 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.

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 Minerals Management Service (the "MMS") 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, President Bush signed into law the Energy Policy Act of 2005 (the "2005 EPA"). 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, MMS 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.

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 MMS pursuant to the OCSLA. These leases are issued through competitive bidding and contain relatively standardized terms. These leases require compliance with detailed MMS regulations and orders that are subject to interpretation and change by the MMS.

For offshore operations, lessees must obtain MMS 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 MMS prior to the commencement of drilling. The MMS has promulgated regulations requiring offshore production facilities located on the Outer Continental Shelf to meet stringent engineering and construction specifications. The MMS also has regulations restricting the flaring or venting of natural gas, and has proposed to amend such regulations to prohibit the flaring of liquid hydrocarbons and oil without prior authorization. Similarly, the MMS 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 MMS 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 MMS. Under some circumstances, the MMS 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.

The MMS also administers the collection of royalties under the terms of the OCSLA and the oil and gas leases issued under the Act. 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 MMS. The MMS regulations governing the calculation of royalties and the valuation of crude oil produced from federal leases provide that the MMS will collect royalties based upon the market value of oil produced from federal leases. The 2005 EPA formalizes the royalty in-kind program of the MMS, providing that the MMS may take royalties in-kind if the Secretary of the Interior determines that the benefits are greater than or equal to the benefits that are likely to have been received had royalties been taken in value. 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 MMS. 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 MMS 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.

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. Neither we nor our predecessors have been designated as a potentially responsible party by the USEPA or a state under CERCLA or a similar state law with respect to any such site.

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 believe we currently have established adequate financial responsibility. While financial responsibility requirements under OPA may be amended to impose additional costs on us, the impact of any change in these requirements should not be any more burdensome to us than to others similarly situated.

Clean Water Act. 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.

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.

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 10,000 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 100 full-time employees as of December 31, 2008. 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. On June 2, 2008, we submitted our Section 303A Annual CEO certification to the New York Stock Exchange.

ITEM 1A. RISK FACTORS

Risks Related to Our Business, Industry and Strategy

Oil and natural gas prices are volatile, and have declined substantially since June 30, 2008. An extended decline in the prices of oil and natural gas would likely have a material adverse effect on our financial condition.

Our revenues, results of operations, profitability and future growth, and the carrying value of our oil and natural gas properties depend to a large degree on prevailing oil and natural gas prices. 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 oil and natural gas have declined substantially since June 30, 2008 and remain 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, including price controls adopted by the Federal Energy Regulatory Commission;
- political instability in the Middle East and elsewhere;
- the price 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 my 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 and results of operations.

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

As widely reported, economic conditions in the United States and globally have been deteriorating. Financial markets in the United States, Europe and Asia have been experiencing 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. Unemployment has risen while business and consumer confidence have declined and there are fears of a prolonged recession. Although we cannot predict the impacts on us of the deteriorating 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 the deteriorating economic conditions which could negatively impact the revenues, margins and profitability of our oil and natural gas business;

- we may be unable to obtain adequate funding under our bank credit facility due to reductions in our borrowing base as a result of a redetermination due to lower oil and gas prices or lending counterparties being unwilling or unable to meet their funding obligations;

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

- 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; or

- our commodity hedging arrangements could become ineffective if our counterparties are unable to perform their obligations or seek bankruptcy protection.

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, 2008, the aggregate amount of our outstanding indebtedness, net of available cash on hand, was approximately $255 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 10 3/8% senior notes due 2012, which we refer to as our 10 3/8% 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 indenture governing our 10 3/8% notes and the agreements governing such other 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;

- we will need to use a substantial portion of our cash flows to pay principal and interest on our debt, approximately $15.6 million per year for interest on our 10 3/8% notes alone, and to pay quarterly dividends, if declared by our Board of Directors, on our Series B Preferred Stock, 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.

In addition, we may be unable to obtain adequate funding under our bank credit facility because (i) our borrowing base under our current revolving credit facility may decrease as the result of a redetermination, reducing it due to lower oil or natural gas prices, operating difficulties, declines in reserves, lending requirements or regulations, or for any other reason in our lenders' discretion or (ii) our lending counterparties may be unwilling or unable to meet their funding obligations. If our revised borrowing base, which is scheduled to be redetermined by March 31, 2009, is less than $130 million, we will be obligated to repay the amount by which our aggregate credit exposure under our bank credit facility exceeds the revised borrowing base within forty-five days after the revised borrowing base is determined.

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 3/8% notes, and meet our other obligations. If we do not have enough money to service our debt, we may be required to refinance all or part of our existing debt, including our 10 3/8% 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 3/8% 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 oil and natural gas.

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 3/8% 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 3/8% 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.

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

Our ability to execute our long-term operating strategy is highly dependent on our having access to capital when the need arises. We have historically addressed our long-term liquidity needs through the use of bank credit facilities, second lien term credit facilities, the issuance of equity and debt securities, the use of proceeds from the sale of assets and the use of 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 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.

We may not be able to fund our planned capital expenditures.

Although our capital expenditure budget is reduced in 2009, when compared to 2008 and other recent years, we spend and will continue to spend a substantial amount of capital for the development, exploration, acquisition and production of oil and natural gas reserves. If extended or further declines in oil and natural gas prices, operating difficulties or other factors, many of which are beyond our control, cause our revenues or cash flows from operations to decrease, we may be limited in our ability to spend the capital necessary to continue our drilling program. We may be forced to raise additional debt or equity, sell properties or assets or enter into joint venture arrangements with industry partners to fund such expenditures. We cannot assure you that additional financings or cash generated by operations will be available to meet these requirements.

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 3/8% notes contain a number of significant covenants that, among other things, restricts or limits our ability to:

- dispose of assets;
- incur a certain level of borrowings under our credit facility and incur or guarantee additional indebtedness and issue certain types of preferred stock;
- pay dividends on our capital stock;
- create liens on our assets;
- enter into sale and leaseback transactions;
- enter into specified investments or acquisitions;
- repurchase, redeem or retire our capital stock or subordinated debt;
- merge or consolidate, or transfer all or substantially all of our assets and the assets of our subsidiaries;
- engage in specified transactions with subsidiaries and affiliates; or
- other corporate activities.

Also, our bank credit facility and the indenture governing our 10 3/8% 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 3/8% 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 3/8% notes. A default, if not cured or waived, could result in acceleration of all indebtedness outstanding under our bank credit facility and our 10 3/8% notes. The accelerated debt would become immediately due and payable. If that should occur, we may not be able to pay all such debt or to borrow sufficient funds to refinance it. Even if new financing were then available, it may not be on terms that are acceptable to us.

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 tropical weather disturbances.

Approximately half of our production and 32% of our reserves are located in the Gulf of Mexico and along the Gulf Coast Basin. Operations in this area are subject to tropical weather disturbances. Some of these disturbances can be severe enough to cause substantial damage to facilities and possibly interrupt production. Certain of our Gulf Coast Basin properties have experienced damages and production downtime as a result of recent storms including Hurricanes Katrina and Rita, and more recently Hurricanes Gustav and Ike. In accordance with customary industry practices, we maintain insurance against some, but not all, of these risks.

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.

Lower oil and natural gas prices may cause us to record ceiling test write-downs.

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. As a result of the decline in commodity prices, during 2008 we recognized $266.2 million in ceiling test write-downs. We may recognize additional write-downs if commodity prices continue to decline or if we experience substantial downward adjustments to our estimated proved reserves.

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.

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.

You should not place undue reliance on reserve information because reserve information represents estimates.

This Form 10-K contains estimates of historical oil and natural gas reserves, and the historical estimated future net cash flows attributable to those reserves, prepared by Ryder Scott Company, L.P. and Netherland, Sewell and Associates, Inc. our independent petroleum and geological engineers. Our estimate of proved reserves is based on the quantities of oil, gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

There are, however, numerous uncertainties inherent in estimating quantities of proved reserves and cash flows from such reserves, including factors beyond our control and the control of Ryder Scott and Netherland, Sewell and Associates, Inc. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of an estimate of quantities of reserves, or of cash flows attributable to these reserves, is a function of:

- the available data;
- assumptions regarding future oil and natural gas prices;
- estimated expenditures for future development and exploitation activities; and
- engineering and geological interpretation and judgment.

Reserves and future cash flows may also be subject to material downward or upward revisions based upon production history, development and exploitation activities and oil and natural gas prices. Actual future production, revenue, taxes, development expenditures, operating expenses, quantities of recoverable reserves and the value of cash flows from those reserves may vary significantly from the assumptions and estimates in this document. In calculating reserves on an Mcfe basis, oil and natural gas liquids were converted to natural gas equivalent at the ratio of six Mcf of natural gas to one Bbl of oil or natural gas liquid.

Approximately 27% of our estimated proved reserves at December 31, 2008 are undeveloped and 12% are developed, non-producing. Estimates of undeveloped and non-producing reserves, by their nature, are less certain. 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 present value of future net revenues referred to in this document is the current market value of our estimated oil and natural gas reserves. In accordance with Commission requirements, the estimated discounted future net cash flows from proved reserves are based on prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. Any changes in consumption by 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, which is required by the Commission to be used in calculating discounted future net cash flows for reporting purposes, 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 natural gas and oil prices and to achieve more predictable cash flow. Our hedges at December 31, 2008 are costless collars and swap contracts that are placed with the commodity trading branches of JP Morgan and Calyon, each of whom participates 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 contract 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 natural gas and oil. Oil and gas hedges increased (reduced) our total oil and gas sales by approximately ($8.3) million, $9.9 million and $6.8 million during 2008, 2007 and 2006, respectively. We cannot assure you that the hedging transactions we have entered into, or will enter into, will adequately protect us from fluctuations in natural gas and oil 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.

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 2008, our stock price ranged from a low of $4.45 per share (on December 5, 2008) to a high of $29.18 per share (on July 2, 2008). 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, 2008, we had reserved approximately 2.6 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.

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 3/8% 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 2. PROPERTIES

For a description of the Company's recent acquisition, exploration and development activities, see Item 1. Business–2008 Financial and Operational Summary.

Oil and Gas Reserves

The following table sets forth certain information about our estimated proved reserves as of December 31, 2008.

	Proved Developed	Proved Undeveloped	Total Proved
Oil (MBbls)	2,030	171	2,201
Natural Gas and NGL (MMcfe)	124,020	48,166	172,186
Estimated pre-tax future net cash flows	$407,917,074	$58,531,564	$466,448,638
Discounted pre-tax future net cash flows	$315,757,469	$11,435,677	$327,193,146

At December 31, 2008, our standardized measure of discounted cash flows, which includes the estimated impact of future income taxes, totaled $314.8 million (see Note 13 to our financial statements). Ryder Scott Company, L.P. and Netherland, Sewell and Associates, Inc., our independent petroleum engineers, prepared the estimates of proved reserves and future net cash flows (and present value thereof) attributable to such proved reserves at December 31, 2008. Ryder Scott Company, L.P. prepared the estimates related to our Gulf Coast Basin, including offshore Louisiana, and East Texas properties and Netherland, Sewell and Associates, Inc. prepared the estimates of our Arkansas and Oklahoma properties. The estimates prepared by Ryder Scott Company, L.P. accounted for approximately 55% of the total proved reserves (on a Bcfe basis) at December 31, 2008 and 71% of the total estimated discounted pre-tax future net cash flows. The estimates prepared by Netherland, Sewell and Associates, Inc. accounted for the remaining 45% of our total proved reserves (on a Bcfe basis) at December 31, 2008 and 29% of the estimated discounted pre-tax future net cash flows. Reserves were estimated using oil and gas prices and production and development costs in effect at December 31, 2008 without escalation, and were prepared in accordance with Securities and Exchange Commission regulations regarding disclosure of oil and gas reserve information. The product prices used in developing the above estimates averaged $41.53 per barrel of oil and $4.64 per Mcfe of gas. The above cash flow amounts include a reduction for estimated plugging and abandonment costs that has been reflected as a liability on our balance sheet at December 31, 2008, in accordance with Statement of Financial Accounting Standards No. 143.

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

Production, Pricing and Production Cost Data

The following table sets forth our production, pricing and production cost data during the periods indicated:

	Year Ended December 31,		
	2008	2007	2006
Production:			
Oil (Bbls)	680,571	1,079,672	694,724
Gas (Mcfe)	29,708,204	24,965,789	21,528,323
Total Production (Mcfe)	33,791,630	31,443,821	25,696,667
Average sales prices (1):			
Oil (per Bbl)	$ 97.49	$ 70.52	$ 60.91
Gas (per Mcfe)	8.16	7.21	7.04
Per Mcfe	9.13	8.15	7.54
Average Production Cost per Mcfe (2)	$ 1.69	$ 1.27	$ 1.61

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(1) Includes the effects of hedges.

(2) Production costs include lease operating costs and 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:

	2008		2007		2006	
	Gross	Net	Gross	Net	Gross	Net
Exploration:						
Productive	103	27.64	54	26.12	37	15.82
Non-productive	6	1.63	9	2.86	4	0.95
Total	109	29.27	63	28.98	41	16.77
Development:						
Productive	41	10.77	22	7.89	66	26.40
Non-productive	-	-	2	0.15	6	2.89
Total	41	10.77	24	8.04	72	29.29

We owned working interests in 16 gross (8 net) producing oil wells and 893 gross (310 net) producing gas wells at December 31, 2008. Of the 909 gross productive wells at December 31, 2008, 14 had dual completions. At December 31, 2008, we had 34 gross wells in progress.

Leasehold Acreage

The following table shows our approximate developed and undeveloped (gross and net) leasehold acreage as of December 31, 2008:

	Leasehold Acreage			
	Developed		Undeveloped	
	Gross	Net	Gross	Net
Mississippi	721	458	88	56
Alabama	90	30	2,924	1,898
Arkansas	7,973	2,636	44,016	15,451
Louisiana	9,430	3,524	13,074	3,920
Oklahoma	107,537	41,077	32,342	30,030
Texas	19,821	10,046	43,494	30,460
Federal Waters	46,304	34,187	51,534	30,603
Total	191,876	91,958	187,472	112,418

Leases covering 7% of our net undeveloped acreage will expire in 2009, 24% in 2010, 3% in 2011 and 66% thereafter.

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.

ITEM 3. LEGAL PROCEEDINGS

PetroQuest is involved in litigation relating to claims arising out of its operations in the normal course of business, including workmen's compensation claims, tort claims and contractual disputes. Some of the existing known claims against us are covered by insurance subject to the limits of such policies and the payment of deductible amounts by us. Management believes that the ultimate disposition of all uninsured or unindemnified matters resulting from existing litigation will not have a material adverse effect on PetroQuest's business or financial position.

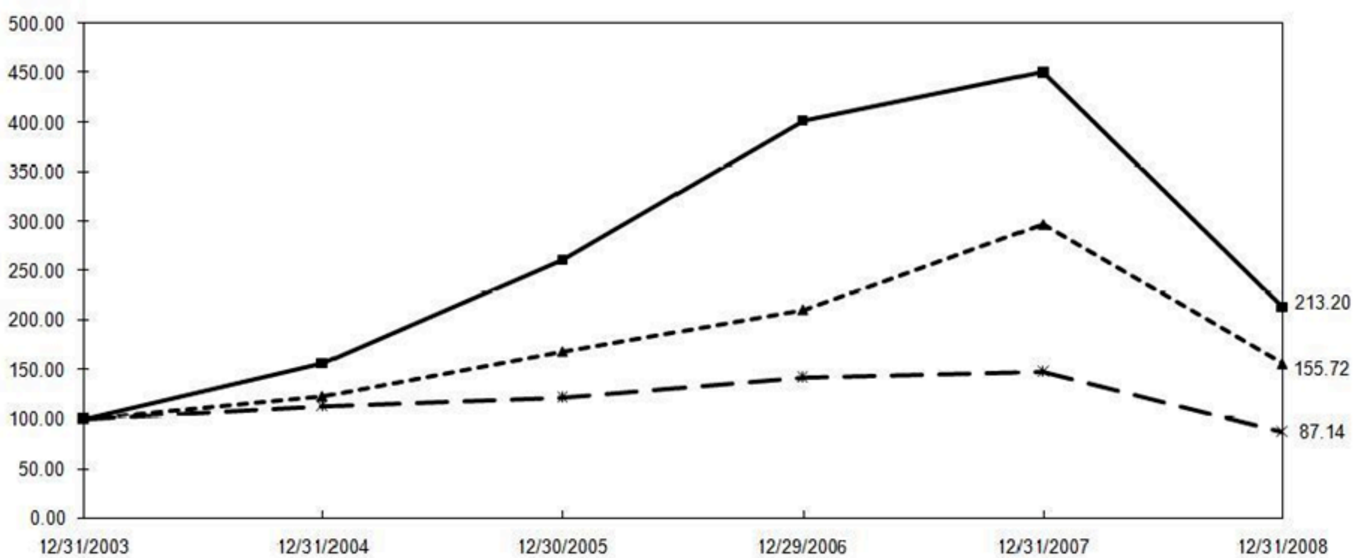
ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

There were no matters submitted to a vote of security holders during the fourth quarter of 2008.

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, 2008.



	Dec-2003	Dec-2004	Dec-2005	Dec-2006	Dec-2007	Dec-2008
PetroQuest Energy Inc.	100.00	156.46	261.19	401.87	451.08	213.20
NYSE/AMEX Stock Market (US Companies)	100.00	113.29	121.38	142.00	147.97	87.14
NYSE Stocks (SIC 1310-1319 US Companies) Crude Petroleum and Natural Gas	100.00	122.88	168.08	210.41	296.75	155.72

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:

	NYSE Stock Market	
	High	Low
2007		
1st Quarter	$ 13.57	$ 10.08
2nd Quarter	15.99	11.39
3rd Quarter	15.13	10.02
4th Quarter	14.99	10.69
2008		
1st Quarter	$ 18.07	$ 10.77
2nd Quarter	28.16	17.17
3rd Quarter	29.18	13.15
4th Quarter	15.09	4.45

As of February 24, 2009, there were 415 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 3/8% senior notes, and, in some circumstances, by 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, 2008.

	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, 2008	-	-	-	-
November 1 - November 30, 2008	-	-	-	-
December 1 - December 31, 2008	7,779	$4.68	-	-

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(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, 2008 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,				
	2008 (1)	2007	2006	2005	2004
	(in thousands except per share data)				
Revenues	$ 313,958	$ 262,334	$ 199,520	$ 120,552	$ 84,595
Net income (loss) available to common stockholders	(102,100)	39,245	23,986	21,417	16,348
Net income (loss) available to common stockholders per share:					
Basic	(2.08)	0.82	0.50	0.46	0.37
Diluted	(2.08)	0.79	0.49	0.44	0.35
Oil and gas properties, net	512,861	554,850	431,814	365,183	211,683
Total assets	670,249	644,347	518,290	431,470	231,617
Long-term debt	278,998	148,755	195,537	158,340	38,500
Stockholders' equity	237,487	302,317	189,711	144,537	121,277

(1) The year ended December 31, 2008 includes a ceiling test write-down of $266.2 million, $167.1 million net of tax benefit, or $3.41 share.

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, which from the commencement of operations in 1985 through 2002, was 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.

Utilizing the cash flow generated by our higher margin Gulf Coast Basin assets, we have accelerated our penetration into longer life basins in Oklahoma, Arkansas and Texas through significantly increased and successful drilling activity and selective acquisitions. Specific asset diversification activities include the 2003 acquisition of proved reserves and acreage in the Southeast Carthage Field in East Texas. In 2004, we entered the Arkoma Basin in Oklahoma by building an acreage position, drilling wells and acquiring proved reserves. During 2005 and 2006, we acquired additional acreage in Oklahoma and Texas, initiated an expanded drilling program in these areas, opened an exploration office in Tulsa, Oklahoma and divested several mature, high-cost Gulf of Mexico fields. During 2007, we acquired a leasehold position in Arkansas and continued to robustly drill in Oklahoma and Texas. During 2008, we significantly increased our acreage position in Oklahoma and increased the pace of drilling operations in our longer life basins as we invested $260.4 million in Oklahoma, Arkansas and Texas.

Through these efforts, at December 31, 2008, 68% of our estimated proved reserves were located in longer life basins as compared to 61% at December 31, 2007 and 52% at December 31, 2006. During 2008, 47% of our production was derived from longer life basins versus 27% and 29% during 2007 and 2006, respectively. For the fifth consecutive year, we achieved annual company records for production and estimated proved reserves. During 2008 we increased these metrics by 7% and 18%, respectively, from the levels achieved during 2007. Our results over the last five years reflect our consistent drilling success and correlate directly with the implementation of our asset diversification strategy during 2003. Comparing 2008 results with those in 2003, we have grown production by 250% and proved reserves by 123%.

Our 2009 capital budget is expected to range between $80 million and $100 million. We plan to fund these drilling expenditures with cash flow from operations. In response to the impact that the decline in commodity prices has on our cash flow, and the deteriorated condition of the financial markets caused by the global financial crisis, our expected 2009 capital expenditures are significantly reduced as compared to 2008. Because we operate the majority of our proved reserves, we expect to be able to control the timing of a substantial portion of our capital investments. As a result of this flexibility, we plan to actively manage our 2009 capital budget to stay within our projected cash flow from operations, with a goal of strengthening our balance sheet, based upon our expectations of commodity prices, production rates and capital costs.

Critical Accounting Policies and Estimates

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.

Oil and natural gas prices declined significantly during the third and fourth quarters of 2008. At December 31, 2008, we computed the estimated future net cash flows from our proved oil and gas reserves, discounted at 10%, using average year-end prices, including hedges, of $4.86 per Mcfe and $45.21 per barrel. Due to the low market prices at September 30, 2008 and December 31, 2008, our capitalized costs exceeded the full cost ceiling, resulting in $266.2 million of non-cash ceiling test write-downs of our oil and gas properties during 2008.

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 continue to decline, even for only a short period of time, or if we have downward revisions to our estimated proved reserves, it is possible that additional 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.

Reserve Estimates

Our estimates of proved oil and gas reserves constitute quantities that we are reasonably certain of recovering in future years. 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, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. 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 quality of available data, engineering and geological interpretation and 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, all of which may in fact vary considerably from actual results. The future drilling costs associated with reserves assigned to proved undeveloped locations may ultimately increase to a level where these reserves may be later determined to be uneconomic. For these reasons, estimates of the economically recoverable quantities of expected oil and gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows may vary substantially. 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. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and such variance may be material.

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, 2008, 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.

New Accounting Standards

In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities- an amendment of FASB Statement No.133" ("SFAS No. 161"). SFAS No. 161 requires enhanced disclosures about derivative and hedging activities, and is effective for financial statements issued for fiscal years and interim periods beginning after

November 15, 2008. We adopted SFAS No. 161 on January 1, 2009 with no impact on our financial position or results of operations.

In December 2007, the FASB issued SFAS No. 141(R), "Business Combinations" ("SFAS No. 141(R)"). SFAS No. 141(R) replaces SFAS No. 141, "Business Combinations," and establishes principles and requirements for the recognition and measurement by an acquirer in its financial statements of the identifiable assets acquired, the liabilities assumed, and any non-controlling interest in the acquiree. The statement also establishes principles and requirements for the recognition and measurement of the goodwill acquired in the business combination or the gain from a bargain purchase and for information disclosed in its financial statements. SFAS No. 141(R) applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008.

In February 2007, the FASB issued SFAS No. 159 "The Fair Value Option for Financial Assets and Liabilities" ("SFAS No. 159"). SFAS No. 159 permits entities to choose to measure certain financial instruments and certain other items at fair value. We adopted SFAS No. 159 on January 1, 2008 and elected not to account for any other assets or liabilities at fair value. As a result, the adoption had no impact on our financial statements.

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements" ("SFAS No. 157"). SFAS No. 157 defines fair value, establishes a framework for measuring fair value under generally accepted accounting principles and expands disclosure about fair value measurements. We adopted SFAS No. 157 on January 1, 2008 (see Note 6 to our financial statements).

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, 2008, 2007 and 2006. Our historical results are not necessarily indicative of results to be expected in future periods.

	Year Ended December 31,		
	2008	2007	2006
Production:			
Oil (Bbls)	680,571	1,079,672	694,724
Gas (Mcfe)	29,708,204	24,965,789	21,528,323
Total Production (Mcfe)	33,791,630	31,443,821	25,696,667
Sales:			
Total oil sales	$ 66,349,344	$ 76,138,234	$ 42,317,332
Total gas sales	242,273,860	180,084,794	151,544,026
Total oil and gas sales	$ 308,623,204	$ 256,223,028	$ 193,861,358
Average sales prices:			
Oil (per Bbl)	$ 97.49	$ 70.52	$ 60.91
Gas (per Mcfe)	8.16	7.21	7.04
Per Mcfe	9.13	8.15	7.54

The above sales and average sales prices include increases (reductions) to revenue related to the settlement of gas hedges of ($6,160,000), $10,713,000 and $9,634,000 and oil hedges of ($2,124,000), ($791,000) and ($2,785,000) for the years ended December 31, 2008, 2007 and 2006, respectively.

Comparison of Results of Operations for the Years Ended December 31, 2008 and 2007

Net income (loss) available to common stockholders totaled ($102,100,000) and $39,245,000 for the years ended December 31, 2008 and 2007, respectively. The decline in net income during 2008 was primarily attributable to the following:

Production. During September 2008, the majority of our Gulf Coast Basin properties were impacted by Hurricanes Gustav and Ike and we estimate that approximately 2 Bcfe, which would have been produced during the third and fourth quarters of 2008, was shut-in and deferred as a result of the storms. Oil production during the year ended December 31 2008 decreased 37% from 2007 primarily due to normal production declines at our Ship Shoal 72 and Turtle Bayou Fields, which provide approximately one-half of our total oil production. Hurricane shut-in time also contributed to the decline in oil production. Currently, nearly all of our Gulf Coast Basin production has been restored.

During late 2007, we began drilling operations on our Arkansas acreage. As a result of production from this new basin and our continued drilling success in longer life basins, where the production is primarily natural gas, our gas production during 2008 increased 19% from the year ended December 31, 2007. The increase in gas production during 2008 was partially offset by the downtime we experienced as a result of the hurricanes. Overall, production during 2008 was 7% higher than in 2007.

We have achieved company records for production in each of the last five years. As a result of low commodity prices and our intention to completely fund our 2009 drilling activities with cash flow from operations, our 2009 capital expenditures budget will be significantly less than our spending in 2008. As a result, we expect that total production in 2009 will generally approximate 2008 production levels.

Prices. Including the effects of our hedges, average oil prices per barrel during 2008 were $97.49, as compared to $70.52 during 2007. Average gas prices per Mcf were $8.16 during 2008, as compared to $7.21 during 2007. Stated on an Mcfe basis, unit prices received during 2008 were 12% higher than the prices received during 2007; however, oil and gas prices declined significantly during the third and fourth quarters of 2008. See "Liquidity and Capital Resources" below for a discussion of the impact of oil and gas prices on our revenues, cash flow and bank credit facility.

Revenue. Oil and gas sales during the year ended December 31, 2008 totaled $308,623,000, a 20% increase from oil and gas sales of $256,223,000 during 2007. The increased revenue during 2008 was primarily the result of higher average pricing and increased gas production. Based on our 2009 outlook for oil and gas prices, we expect oil and gas sales to decline during 2009, as compared to 2008.

During 2008, we sold the majority of our gas gathering assets located in Oklahoma for net proceeds of $43,170,000 and recorded a $26,812,000 gain. Proceeds from the sale were used to repay a portion of our bank borrowings.

Expenses. Lease operating expenses during 2008 increased to $44,665,000, as compared to $31,965,000 during 2007. On a unit of production basis, operating expenses totaled $1.32 per Mcfe and $1.02 per Mcfe during 2008 and 2007, respectively.

The increase in lease operating expenses was primarily due to the overall increase in the cost of materials, transportation, fuel and other services during 2008 as compared to 2007. For 2009, we believe the costs of services and materials in the markets in which we operate will decline as the demand for such materials and services weakens as a result of the substantial decline in commodity prices and the overall condition of the oil and gas industry and the global economy.

Production taxes totaled $12,292,000 and $7,859,000 during 2008 and 2007, respectively. The increase in 2008 production taxes is primarily due to higher average prices and increased production from our Oklahoma, Arkansas and Texas properties. Additionally, there was a 7% increase in the Louisiana gas severance tax rate effective July 1, 2008.

General and administrative expenses during 2008 totaled $23,249,000, as compared to expenses of $21,162,000 during 2007. Included in general and administrative expenses was share-based compensation expense relative to SFAS 123(R) as follows (in thousands):

	Years Ended December 31, 2008	Years Ended December 31, 2007
Stock options:		
Incentive Stock Options	$ 1,316	$ 1,250
Non-Qualified Stock Options	2,729	1,869
Restricted stock	5,537	6,699
Share-based compensation	$ 9,582	$ 9,818

Excluding share-based compensation, general and administrative expenses during 2008 increased by 20%, as compared to 2007. Employee-related costs, including our payment of employee taxes for the vesting of certain restricted stock grants, represented the majority of the increase in expenses during 2008. We expect that general and administrative expenses for 2009 will be less than 2008 amounts.

Depreciation, depletion and amortization ("DD&A") expense on oil and gas properties for 2008 totaled $131,348,000, or $3.89 per Mcfe, as compared to $116,384,000, or $3.70 per Mcfe during 2007. The increase in DD&A expense during 2008 was primarily due to the higher cost of drilling and completion operations during 2008, as compared to 2007, and the negative impact that declining oil and gas prices had on our proved reserves at September 30, 2008 and December 31, 2008.

The prices of oil and natural gas used in computing our estimated proved reserves at September 30, 2008 and December 31, 2008 were substantially below the market prices received during the majority of 2008. The lower oil and natural gas prices had a negative impact on our proved reserves from certain of our longer-life properties and reduced the estimated discounted cash flow from our proved reserves. As a result, we recorded non-cash ceiling test write-downs of our oil and gas properties during 2008 totaling $266,156,000. For 2009, we expect that our DD&A expense on oil and gas properties will decline, as compared to 2008, due to the ceiling test write-downs recorded during 2008. See Note 9, "Ceiling Test" for further discussion of the ceiling test.

Interest expense, net of amounts capitalized on unevaluated properties, totaled $9,327,000 during 2008 as compared to $13,393,000 during 2007. We capitalized $10,525,000 and $6,539,000 of interest during 2008 and 2007, respectively. The increase in the capitalized portion of our interest cost during 2008 was due to the increase in our unevaluated properties, which is primarily the result of leasehold acquisitions made in our longer-life basins.

Income tax expense (benefit) during 2008 totaled ($55,581,000), as compared to $23,664,000 during 2007. The decrease during 2008 is primarily the result of the impact of ceiling test write-downs, offset in part by the gain on the sale of our gas gathering assets. We provide for income taxes at a statutory rate of 35% adjusted for permanent differences expected to be realized, primarily statutory depletion, non-deductible stock compensation expenses and state income taxes.

Comparison of Results of Operations for the Years Ended December 31, 2007 and 2006

Net income available to common stockholders for the year ended December 31, 2007 increased 64% to $39,245,000, as compared to $23,986,000 for the year ended December 31, 2006. The results were attributable to the following components:

Production Oil production during 2007 totaled 1,080 MBbls, a 55% increase from 2006, while natural gas production increased 16% to 25 Bcfe from 2006 gas production of 21.5 Bcfe. On a gas equivalent basis, production for 2007 totaled 31.4 Bcfe, a 22% increase from the 2006 period.

Throughout 2006, we successfully drilled and recompleted several wells at our Ship Shoal 72 Field, which produces substantial oil volumes. As a result of drilling success and the improvement in throughput from a new main field pipeline installed in late 2006, production from Ship Shoal 72 totaled 9.8 Bcfe, or approximately 31% of total company production during 2007, as compared to only 4.5 Bcfe during 2006. In addition, continued drilling success in Oklahoma and Texas resulted in increased production during 2007 from these basins. The increase in production during 2007 was partially offset by the sale of several Gulf of Mexico fields in November 2006. Production from the properties sold in 2006 totaled 1.7 Bcfe.

Prices Average oil prices per barrel during 2007 were $70.52 versus $60.91 during 2006. Average gas prices per Mcf were $7.21 during 2007 as compared to $7.04 during 2006. Stated on a gas equivalent basis, unit prices received during 2007 were 8% higher as compared to the prices received during 2006.

Revenue Oil and gas sales during 2007 increased 32% to $256,223,000, as compared to $193,861,000 during 2006 as a result of increased production volumes and higher realized prices.

During 2007, gas gathering revenue totaled $6,111,000 as compared to $5,659,000 during 2006. The increase in 2007, as compared to 2006, is the result of increased gas volumes being transported through the gas gathering systems.

Expenses Lease operating expenses during 2007 decreased to $31,965,000 as compared to $34,735,000 during 2006. Lease operating costs in 2006 included $5,979,000 of costs related to the Gulf of Mexico properties sold in November 2006.

Production taxes increased to $7,859,000 during 2007 from $6,576,000 during 2006. The increase in 2007 production taxes is primarily due to increased production from our Oklahoma, Texas and onshore Louisiana properties, partially offset by the 28% reduction in the Louisiana severance tax rate effective July 1, 2007.

General and administrative expenses during 2007 totaled $21,162,000, as compared to expenses of $15,122,000 during 2006. Included in general and administrative expenses for the years ended December 31, 2007 and 2006 was share based compensation expense relative to SFAS 123(R) as follows (in thousands):

	Years Ended December 31, 2007	Years Ended December 31, 2006
Stock options:		
Incentive Stock Options	$ 1,250	$ 526
Non-Qualified Stock Options	1,869	1,344
Restricted stock	6,699	3,781
Share based compensation	$ 9,818	$ 5,651

Excluding the impact of share based compensation expense, the resulting 20% increase in general and administrative expenses was primarily attributable to the 31% increase in our staffing during 2007 necessary to manage our increased operational activity. We capitalized $7,522,000 and $6,191,000 of general and administrative costs during 2007 and 2006, respectively.

Depreciation, depletion and amortization ("DD&A") expense on oil and gas properties for 2007 increased 40% to $116,384,000, as compared to $82,928,000 in 2006. The increase in DD&A expense is the result of the growth in our oil and gas properties over the last three years from our significantly expanded drilling activity and several property acquisitions. On an Mcfe basis, the DD&A rate on oil and gas properties totaled $3.70 per Mcfe during 2007 as compared to $3.23 per Mcfe for 2006. The increase in our DD&A expense per Mcfe is primarily due to increased costs to drill for, develop and acquire oil and gas reserves and the impact of six unsuccessful wells drilled in the Gulf Coast Basin during 2007.

During September and October 2007, we issued a total of 1,495,000 shares of Series B cumulative convertible perpetual preferred stock (the "Series B Preferred Stock"). At December 31, 2007, $1,374,000 had been accrued in connection with the initial dividend paid on January 15, 2008. Interest expense, net of amounts capitalized on unevaluated assets, totaled $13,393,000 during 2007 versus $14,513,000 during 2006. The decrease in interest expense in 2007 is the result of the repayment of our bank borrowings in September 2007 with proceeds received from the issuance of the Series B Preferred Stock. We capitalized $6,539,000 and $4,650,000 of interest during 2007 and 2006, respectively.

Income tax expense of $23,664,000 was recognized during 2007 as compared to $14,604,000 during 2006. The increase is primarily due to the higher operating profit during 2007. We provide for income taxes at a statutory rate of 35% adjusted for permanent differences expected to be realized, primarily statutory depletion, non-deductible stock compensation expenses and state income taxes.

Liquidity and Capital Resources

We have financed our acquisition, exploration and development activities to date principally through cash flow from operations, bank borrowings, private and public offerings of equity and debt securities and sales of assets. At December 31, 2008, we had a working capital surplus of $40.1 million compared to a deficit of $43.7 million at December 31, 2007.

The increase in our working capital at December 31, 2008 was primarily attributable to the increase of our hedging asset, which is a function of lower estimated future commodity prices and the increase in our prepaid drilling costs and drilling pipe inventory, which reflects the increase in drilling activity during 2008. Additionally, our accounts payable to vendors and advances from co-owners liabilities decreased at December 31, 2008, as compared to 2007, as a result of the timing of payments made and operated wells completed. Partially offsetting the increases in working capital was an increase in our revenue payable liability, which is a function of higher production at December 31, 2008 as compared to December 31, 2007.

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. Natural gas and oil 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 natural gas and oil 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 natural gas and oil prices.

Source of Capital: Operations

Net cash flow from operations decreased from $223,729,000 in 2007 to $169,061,000 during 2008. The decrease in operating cash flow during 2008 was primarily attributable to the timing of payments made to reduce our accounts payable to vendors and the increase in our drilling pipe inventory and prepaid drilling costs, which is the result of increased drilling activity in 2008 versus 2007.

Source of Capital: Debt

During 2005, we issued $150 million in principal amount of our 10 3/8% Senior Notes due 2012 (the "Notes"), which have numerous covenants including restrictions on liens, incurrence of indebtedness, asset sales, dividend payments and other restricted payments. Interest is payable semi-annually on May 15 and November 15. At December 31, 2008, $1.9 million had been accrued in connection with the May 15, 2009 interest payment and we were in compliance with all of the covenants under the Notes.

On October 2, 2008, we entered into the Credit Agreement (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 for 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. The Credit Agreement matures on February 10, 2012; provided, however, if on or prior to such date we prepay or refinance, subject to certain conditions, the Notes, the maturity date will be extended to October 2, 2013. As of December 31, 2008 we had $130 million of borrowings outstanding under (and no letters of credit issued pursuant to) the Credit Agreement.

The borrowing base under the Credit Agreement is based upon the valuation as of January 1 and July 1 of each year of the reserves attributable to our oil and gas properties. The initial borrowing base is fixed at $150 million until the first borrowing base redetermination, which is scheduled to occur by March 31, 2009. We or the lenders may request two additional borrowing base redeterminations each year. Each time the borrowing base is to be redetermined, 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.

At December 31, 2008, our borrowing base exceeded our outstanding borrowings by $20 million; however, as a result of the declines in commodity prices since the establishment of the borrowing base, we anticipate that our next regularly scheduled borrowing base redetermination, which is scheduled to occur by March 31, 2009, will result in a borrowing base of less than $150 million. As a result of the redetermination, we may be unable to borrow any additional funds under the Credit Agreement, and if the revised borrowing base is less than $130 million, we will be obligated to repay the amount by which our aggregate credit exposure under the Credit Agreement exceeds the revised borrowing base within forty-five days after the revised borrowing base is determined. At December 31, 2008, we had cash and cash equivalents of approximately $24 million that we believe would be sufficient to repay amounts that may be required as a result of the redetermined borrowing base.

The indenture governing the Notes also limits our ability to incur indebtedness under the Credit Agreement. Under the indenture we will not be able to incur additional indebtedness under the Credit Agreement in excess of 20% of our adjusted consolidated net tangible assets (as defined in the indenture). That calculation is based primarily on the valuation of our estimated reserves of oil and natural gas using year-end commodity prices. Until recalculated, we will not be able to incur new indebtedness under the Credit Agreement in excess of approximately $93 million. While the indenture limits the amount of new indebtedness that may be incurred under the Credit Agreement, it does not restrict the amount of that indebtedness that may be outstanding under the Credit Agreement. Therefore, even though the amount of indebtedness under the Credit Agreement at December 31, 2008 exceeds 20% of the adjusted consolidated net tangible assets, we are not required by the indenture to reduce the amount currently outstanding.

The Credit Agreement is secured by a first priority lien on substantially all of our assets and 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 0.0% to 0.75% depending on borrowing base usage) or the adjusted LIBO rate ("Eurodollar") plus a margin (based on a sliding scale of 1.5% to 2.25% depending on borrowing base usage). However, for the first six months of the Credit Agreement, the margin will be 0.5% for ABR loans and 2.0% for Eurodollar loans. Outstanding letters of credit will be charged a participation fee at a per annum rate equal to the margin applicable to Eurodollar loans, a fronting fee and customary administrative fees.

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, 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, 2008, we were in compliance with all of the covenants contained in the Credit Agreement.

Source of Capital: Issuance of Securities

During 2007, we issued a total of 1,495,000 shares of Series B Preferred Stock resulting in net proceeds to us of approximately $71 million. Cash dividends are payable quarterly in the amount of $0.8594 per share of Series B Preferred Stock. Based on the total of 1,495,000 shares of Series B Preferred Stock issued, the annual dividend payment, if declared and paid, is approximately $5.1 million.

After giving effect to the issuance of the Series B Preferred Stock, we have approximately $125 million remaining under an effective universal shelf registration statement relating to the potential public offer and sale of any combination of debt securities, common stock, preferred stock, depositary shares, and warrants. The registration statement does not provide any assurance that we will or could sell any such securities.

Source of Capital: Divestitures

We do not budget for property divestitures; however, we are continually 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 capital to be reinvested in higher rate of return projects or in projects that have longer estimated lives. During 2008, we sold the majority of our gas gathering systems located in Oklahoma for net proceeds of $43.2 million and recorded a $26.8 million gain. The net proceeds from the sale were used to repay a portion of the borrowings outstanding under our bank credit facility. There can be no assurance that we will be able to sell any of our assets in the future.

Use of Capital: Exploration and Development

Our 2009 capital budget, which includes capitalized interest and general and administrative costs, is expected to range between $80 million and $100 million. We plan to continue our strategic focus of funding our drilling expenditures with cash flow from operations. In response to the recent decline in commodity prices and the deteriorated condition of the capital markets caused by the global financial crisis, we have reduced our capital expenditure budget for 2009, as compared to 2008. Because we operate the majority of our proved reserves, we expect to be able to control the timing of a substantial portion of our capital investments. As a result of this flexibility, we plan to actively manage our 2009 capital budget to stay within our projected cash flow from operations, with a goal of strengthening our balance sheet, based upon our expectations of commodity prices, production rates and capital costs.

However, if commodity prices continue to decline or if actual production or costs vary significantly from our expectations, our 2009 exploration and development activities could be reduced further or could require additional financings, which may include sales of equity or debt securities, sales of properties or assets or joint venture arrangements with industry partners. As a result of the current condition of the financial markets, we cannot assure you that such additional financings will be available on acceptable terms, if at all. If we are unable to obtain additional financing, we could be forced to further delay, reduce our participation in or even abandon some of our exploration and development opportunities or be forced to sell some of our assets on an untimely or unfavorable basis.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2008 (in thousands):

	Total	2009	2010	2011	2012	2013	After 2013
10 3/8% senior notes (1)	$ 202,525	$ 15,563	$ 15,563	$ 15,563	$ 155,836	$ -	$ -
Bank debt (1)	145,246	4,550	4,875	5,200	130,621	-	-
Purchase obligations (2)	4,900	4,900	-	-	-	-	-
Operating leases (3)	3,815	1,070	1,039	893	750	63	-
Capital projects (4)	25,633	8,590	557	1,103	1,659	594	13,130
Total	$ 382,119	$ 34,673	$ 22,034	$ 22,759	$ 288,866	$ 657	$ 13,130

(1) Includes principal and estimated interest.
(2) Consists of commitment for the rental of a drilling rig.
(3) Consists primarily of leases for office space and leases for office equipment.
(4) Consists of estimated future obligations to abandon our oil and gas properties.

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 2009, a 10% decline in the estimated average prices we expect to receive for our crude oil and natural gas production would have an approximate $9 million impact on our 2009 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 2008, we paid approximately $8.3 million to 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 JP Morgan and Calyon, both of 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, 2008, 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:			
January - June 2009	Swap	20,000 Mmbtu	$5.62
2009	Swap	10,000 Mmbtu	$7.46
2009	Costless Collar	30,000 Mmbtu	$8.75 - 11.38
Crude Oil:			
2009	Costless Collar	400 Bbls	$100.00 - 168.50

At December 31, 2008, we recognized an asset of approximately $40.6 million related to the estimated fair value of these derivative instruments. Based on estimated future commodity prices as of December 31, 2008, we would realize a $25.6 million gain, net of taxes, as an increase to oil and gas sales during the next 12 months. These gains are expected to be reclassified based on the schedule of oil and gas volumes stipulated in the derivative contracts.

During February 2009, we entered into the following additional gas hedge contracts accounted for as cash flow hedges:

Production Period	Instrument Type	Daily Volumes	Weighted Average Price
Natural Gas:			
July - December 2009	Swap	10,000 Mmbtu	$5.34
2010	Costless Collar	10,000 Mmbtu	$6.00 - $7.15

Debt outstanding under our bank credit facility is subject to a floating interest rate and represents 47% of our total debt as of December 31, 2008. Based upon an analysis, utilizing the actual interest rate in effect and balances outstanding as of December 31, 2008, and assuming a 10% increase in interest rates and no changes in the amount of debt outstanding, the potential effect on interest expense for 2009 is approximately $0.5 million.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Information concerning this Item begins on page F-1.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, the Company's management, including its Chief Executive Officer and Chief Financial Officer, carried out an evaluation of the effectiveness of the Company's disclosure controls and procedures pursuant to Rule 13a-15 of the Securities and Exchange Act of 1934, as amended (the "Exchange Act"). Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded the following:

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

ii. that the Company's disclosure controls and procedures are effective.

Notwithstanding the foregoing, there can be no assurance that the Company's disclosure controls and procedures will detect or uncover all failures of persons within the Company and its consolidated subsidiaries to disclose material information otherwise required to be set forth in the Company's periodic reports. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable, not absolute, assurance of achieving their control objectives.

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, 2008 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, 2008. 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, 2008 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, 2008 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, 2008.

February 26, 2009

/s/ Charles T. Goodson
Charles T. Goodson
Chairman and
Chief Executive Officer

/s/ W. Todd Zehnder
W. Todd Zehnder
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, 2008, 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, 2008, 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, 2008 and 2007, 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, 2008 and our report dated February 26, 2009 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

New Orleans, Louisiana
February 26, 2009

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 Accountant 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 13, 2009, 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 AND 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, 2008 and 2007
Consolidated Statements of Operations for the three years ended December 31, 2008
Consolidated Statements of Cash Flows for the three years ended December 31, 2008
Consolidated Statements of Stockholders' Equity for the three years ended December 31, 2008
Consolidated Statements of Comprehensive Income for the three years ended December 31, 2008
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 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).

3.3 Certificate of Domestication of Optima Petroleum Corporation (incorporated herein by reference to Exhibit 4.4 to Form 8-K filed September 16, 1998).

3.4 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).

	3.5	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).
†	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.
†*	10.3	Form of Nonstatutory Stock Option Agreement under the Incentive Plan.
†*	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.
†	10.5	PetroQuest Energy, Inc. Annual Cash Bonus Plan (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed August 18, 2006).
†	10.6	Amendment to the PetroQuest Energy, Inc. Annual Cash Bonus Plan (incorporated herein by reference to Exhibit 10.7 to Form 8-K filed January 6, 2009).
	10.7	Second Amended and Restated Credit Agreement dated as of November 18, 2005, among PetroQuest Energy, LLC, PetroQuest Energy, Inc., JP Morgan Chase Bank, N.A. as lender, agent and issuer of letters of credit, Macquarie Bank Limited as lender, and Calyon New York Branch as lender and syndication agent (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed November 23, 2005).
	10.8	Amendment No. 1 to Second Amended and Restated Credit Agreement dated as of December 22, 2005, among PetroQuest Energy, LLC, PetroQuest Energy, Inc., Pittrans, Inc., TDC Energy LLC, JP Morgan Chase Bank, N.A. as lender, agent and issuer of letters of credit, Macquarie Bank Limited as lender, and Calyon New York Branch as lender and syndication agent (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed December 22, 2005).
	10.9	Amendment No. 2 to Second Amended and Restated Credit Agreement dated as of November 16, 2006 among PetroQuest Energy, LLC, PetroQuest Energy, Inc., Pittrans, Inc., TDC Energy LLC, JP Morgan Chase Bank, N.A. as lender, agent and issuer of letters of credit, Macquarie Bank Limited as lender, and Calyon New York Branch as lender and syndication agent (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed November 21, 2006).

10.10 Amendment No. 3 to Second Amended and Restated Credit Agreement dated as of September 17, 2007 among PetroQuest Energy, LLC, PetroQuest Energy, Inc., Pittrans, Inc., TDC Energy LLC, JP Morgan Chase Bank, N.A. as lender, agent and issuer of letters of credit, Macquarie Bank Limited as lender, and Calyon New York Branch as lender and syndication agent (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed September 18, 2007).

10.11 Amendment No. 4 to Second Amended and Restated Credit Agreement dated as of September 19, 2007 among PetroQuest Energy, LLC, PetroQuest Energy, Inc., Pittrans, Inc., TDC Energy LLC, JP Morgan Chase Bank, N.A. as lender, agent and issuer of letters of credit, Macquarie Bank Limited as lender, and Calyon New York Branch as lender and syndication agent (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed September 24, 2007).

10.12 Amendment No. 5 to Second Amended and Restated Credit Agreement, dated effective as of April 1, 2008, among PetroQuest Energy, L.L.C., PetroQuest Energy, Inc., Pittrans, Inc., TDC Energy LLC, JPMorgan Chase Bank, N.A. as lender, agent and issuer of letters of credit, Macquarie Bank Limited as lender, and Calyon New York Branch as lender and syndication agent (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed April 25, 2008).

10.13 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).

† 10.14 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).

† 10.15 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).

† 10.16 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).

† 10.17 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).

† 10.18 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).

†*10.19 Amended Executive Employment Agreement dated effective as of December 31, 2008, between Mark K. Stover and PetroQuest Energy, Inc.

†* 10.20 Amended Executive Employment Agreement dated effective as of December 31, 2008, between Dalton F. Smith III and PetroQuest Energy, Inc.

†* 10.21 Amended Executive Employment Agreement dated effective as of December 31, 2008, between J. Bond Clement and PetroQuest Energy, Inc.

† 10.22 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).

† 10.23 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).

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.

*23.3 Consent of Netherland, Sewell and Associates, Inc.

*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.

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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. Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

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

Developmental well. A well drilled into a proved natural gas or oil 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 and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend 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 either 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.

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

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 developed non-producing reserves. Proved developed reserves expected to be recovered from zones behind casing in existing wells.

Proved developed producing reserves ("PDP"). Proved developed reserves that are expected to be recovered from completion intervals currently open in existing wells and capable of production to market.

Proved developed reserves. Proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.

Proved reserves. The estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved undeveloped reserves. Proved reserves 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.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.

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.

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 26, 2009.

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 26, 2009.

By: /s/ Charles T. Goodson CHARLES T. GOODSON	Chairman of the Board, President, Chief Executive Officer and Director (Principal Executive Officer)
By: /s/ W. Todd Zehnder W. TODD ZEHNDER	Executive Vice President, Chief Financial Officer, Treasurer (Principal Financial Officer)
By: /s/ J. Bond Clement J. BOND CLEMENT	Senior Vice President and Chief Accounting Officer (Principal 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: E. WAYNE NORDBERG	Director
By: /s/ William W. Rucks, IV WILLIAM W. RUCKS, IV	Director

INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
PetroQuest Energy, Inc.

We have audited the accompanying consolidated balance sheets of PetroQuest Energy, Inc. as of December 31, 2008 and 2007, 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, 2008. 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, 2008 and 2007, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2008, in conformity with U.S. generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), PetroQuest Energy, Inc.'s internal control over financial reporting as of December 31, 2008, 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 26, 2009 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

New Orleans, Louisiana
February 26, 2009

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

	December 31, 2008	December 31, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 23,964	$ 16,909
Revenue receivable	20,074	22,820
Joint interest billing receivable	24,259	22,936
Hedging asset	40,571	-
Prepaid drilling costs	11,523	1,448
Drilling pipe inventory	25,898	-
Other current assets	1,530	3,984
Total current assets	147,819	68,097
Property and equipment:		
Oil and gas properties:		
Oil and gas properties, full cost method	1,225,304	907,083
Unevaluated oil and gas properties	119,847	80,297
Accumulated depreciation, depletion and amortization	(832,290)	(432,530)
Oil and gas properties, net	512,861	554,850
Gas gathering assets	4,644	22,040
Accumulated depreciation and amortization of gas gathering assets	(900)	(6,640)
Total property and equipment	516,605	570,250
Other assets, net of accumulated depreciation and amortization of $6,237 and $11,238, respectively	5,825	6,000
Total assets	$ 670,249	$ 644,347
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable to vendors	$ 70,643	$ 78,273
Advances from co-owners	5,349	12,870
Oil and gas revenue payable	15,305	5,771
Accrued interest and preferred stock dividend	3,696	3,320
Asset retirement obligation	8,590	5,280
Other accrued liabilities	4,094	6,326
Total current liabilities	107,677	111,840
Bank debt	130,000	-
10 3/8% Senior Notes	148,998	148,755
Asset retirement obligation	17,043	12,171
Deferred income taxes	28,845	69,160
Other liabilities	199	104
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 49,319 and 48,414 shares, respectively	49	48
Paid-in capital	216,253	204,979
Accumulated other comprehensive income (loss)	25,560	(435)
Retained earnings (deficit)	(4,376)	97,724
Total stockholders' equity	237,487	302,317
Total liabilities and stockholders' equity	$ 670,249	$ 644,347

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,		
	2008	2007	2006
Revenues:			
Oil and gas sales	$ 308,623	$ 256,223	$ 193,861
Gas gathering revenue	5,335	6,111	5,659
	313,958	262,334	199,520
Expenses:			
Lease operating expenses	44,665	31,965	34,735
Production taxes	12,292	7,859	6,576
Depreciation, depletion and amortization	134,340	119,969	85,858
Ceiling test writedown	266,156	-	-
Gas gathering costs	2,309	4,120	3,637
General and administrative	23,249	21,162	15,122
Accretion of asset retirement obligation	1,317	923	1,513
Interest expense	9,327	13,393	14,513
	493,655	199,391	161,954
Gain on sale of gas gathering assets	26,812	-	-
Other income	344	1,340	1,024
Income (loss) from operations	(152,541)	64,283	38,590
Income tax expense (benefit)	(55,581)	23,664	14,604
Net income (loss)	(96,960)	40,619	23,986
Preferred stock dividend	5,140	1,374	-
Net income (loss) available to common stockholders	$ (102,100)	$ 39,245	$ 23,986
Earnings per common share:			
Basic			
Net income (loss) per share	$ (2.08)	$ 0.82	$ 0.50
Diluted			
Net income (loss) per share	$ (2.08)	$ 0.79	$ 0.49
Weighted average number of common shares:			
Basic	48,971	48,108	47,537
Diluted	48,971	49,679	48,936

See accompanying Notes to Consolidated Financial Statements.

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

	Year Ended December 31, 2008	2007	2006
Cash flows from operating activities:			
Net income (loss)	$ (96,960)	$ 40,619	$ 23,986
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Deferred tax expense (benefit)	(55,581)	23,664	14,604
Gain on sale of gas gathering assets	(26,812)	-	-
Depreciation, depletion and amortization	134,340	119,969	85,858
Ceiling test writedown	266,156	-	-
Share-based compensation expense	9,582	9,818	5,651
Accretion of asset retirement obligation	1,317	923	1,513
Amortization expense and other	1,492	1,187	1,140
Payments to settle asset retirement obligations	(19,377)	(6,058)	(252)
Changes in working capital accounts:			
Revenue receivable	2,746	(1,053)	725
Joint interest billing receivable	(1,323)	(2,864)	(2,505)
Prepaid drilling costs	(10,075)	3,438	(3,630)
Drilling pipe inventory	(25,898)	-	-
Accounts payable and accrued liabilities	(4,567)	37,050	(13,552)
Advances from co-owners	(7,521)	(521)	7,517
Other	1,542	(2,443)	(1,685)
Net cash provided by operating activities	169,061	223,729	119,370
Cash flows from investing activities:			
Investment in oil and gas properties	(325,936)	(233,436)	(175,277)
Investment in gas gathering assets	(6,204)	(2,968)	(6,363)
Proceeds from sale of gathering assets, net of expenses	43,170	-	-
Proceeds from sale of oil and gas properties and other	2,256	1,277	22,023
Net cash used in investing activities	(286,714)	(235,127)	(159,617)
Cash flows from financing activities:			
Net proceeds from (payments for) share based compensation	1,597	(99)	1,461
Proceeds from preferred stock offering	-	74,750	-
Costs of preferred stock offering	-	(4,041)	-
Payment of preferred stock dividend	(5,439)	-	-
Proceeds from bank borrowings	258,000	23,000	48,000
Repayment of bank borrowings	(128,000)	(70,000)	(11,000)
Deferred financing costs	(1,450)	(98)	(122)
Net cash provided by financing activities	124,708	23,512	38,339
Net increase (decrease) in cash and cash equivalents	7,055	12,114	(1,908)
Cash and cash equivalents at beginning of period	16,909	4,795	6,703
Cash and cash equivalents at end of period	$ 23,964	$ 16,909	$ 4,795
Supplemental disclosure of cash flow information			
Cash paid during the period for:			
Interest	$ 17,851	$ 19,238	$ 17,572
Income taxes	$ -	$ -	$ -

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, 2005	$ 47	$ -	$ 117,441	$ (7,444)	$ 34,493	$ 144,537
Options and warrants exercised	1	-	1,460	-	-	1,461
Share-based compensation expense	-	-	5,651	-	-	5,651
Derivative fair value adjustment, net of tax	-	-	-	14,076	-	14,076
Net income	-	-	-	-	23,986	23,986
December 31, 2006	$ 48	$ -	$ 124,552	$ 6,632	$ 58,479	$ 189,711
Options exercised	-	-	1,051	-	-	1,051
Retirement of shares upon vesting of restricted stock	-	-	(1,150)	-	-	(1,150)
Issuance of preferred stock	-	1	70,708	-	-	70,709
Share-based compensation expense	-	-	9,818	-	-	9,818
Derivative fair value adjustment, net of tax	-	-	-	(7,067)	-	(7,067)
Preferred stock dividend	-	-	-	-	(1,374)	(1,374)
Net income	-	-	-	-	40,619	40,619
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

See accompanying Notes to Consolidated Financial Statements.

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

	Year Ended December 31,		
	2008	2007	2006
Net income (loss)	$ (96,960)	$ 40,619	$ 23,986
Change in fair value of derivative instruments, accounted for as hedges, net of tax benefit (expense) of ($15,267), $4,150 and ($7,903), respectively	25,995	(7,067)	14,076
Comprehensive income (loss)	$ (70,965)	$ 33,552	$ 38,062

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 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.

Oil and Gas Properties

The Company utilizes the full cost method of accounting, which involves capitalizing all acquisition, exploration and development costs incurred for the purpose of finding oil and gas reserves including the costs of drilling and equipping productive wells, dry hole costs, lease acquisition costs and delay rentals. The Company also capitalizes the portion of general and administrative costs, 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 unproved 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 period-end 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 SFAS No. 143 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. See Note 9 for discussion of ceiling test write-downs recognized during 2008.

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.

The net proceeds from the sale were used to repay a portion of the borrowings outstanding under the bank credit facility. The following table summarizes the operating data attributable to the gas gathering systems sold (in thousands):

	Years Ended December 31, 2008	2007	2006
Gas gathering revenue	$ 4,876	$ 5,581	$ 4,835
Expenses:			
Gas gathering costs	(2,247)	(4,120)	(3,637)
Depreciation expense	(1,974)	(2,773)	(2,209)
Income (loss) from operations	$ 655	$ (1,312)	$ (1,011)

Other Assets

Other assets consist primarily of 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.

Drilling Pipe Inventory

Drilling pipe inventory, which is included in current assets, consists of tubular goods and pipe that the Company utilizes in its ongoing exploration and development activities. The cost basis of drilling pipe inventory is depreciated as a component of oil and gas properties once the inventory is used in drilling or other capitalized operations. At December 31, 2008, the market value of the Company's drilling pipe inventory approximated the cost basis.

Income Taxes

The Company accounts for income taxes in accordance with Statement of Financial Accounting Standards (SFAS) No. 109, "Accounting for Income Taxes". 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, 2008 and 2007 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,		
	2008	2007	2006
DCP Midstream	10%	12%	(a)
Cokinos	(a)	(a)	11%
Louis Dreyfus Corporation	11%	16%	12%
Texon LP	23%	32%	22%
Crosstex	11%	(a)	14%
Laclede Energy	11%	(a)	(a)

(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, 2008 and 2007 due to the short-term nature of these accounts. The fair value of the bank debt at December 31, 2008 also approximated book value due to the variable rate of interest charged. Hedging instruments are reflected as assets (liabilities) on the balance sheet at estimated fair values of approximately $40.6 million and ($0.7) million at December 31, 2008 and 2007, respectively, as required under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities". The estimated fair value of the 10 3/8% senior notes due 2012 (the "Notes") at December 31, 2008 was $103.5 million, as compared to the book value, net of discount, of $149 million. At December 31, 2007, the fair value of the Notes was $154.5 million, while the book value of the Notes, net of discount, was $148.8 million. The estimated fair value of the Notes was provided by independent brokers using the actual year-end market quote for the Notes.

Derivative Instruments

Under SFAS No. 133, as amended, the nature of a derivative instrument must be evaluated to determine if it qualifies for hedge accounting treatment. Instruments qualifying for hedge accounting treatment are recorded as an asset or liability measured at fair value and subsequent changes in fair value are recognized in stockholders' equity through other comprehensive income (loss), net of related taxes, to the extent the hedge is effective. All of the Company's derivative instruments qualified for hedge accounting during 2008, 2007 and 2006. 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 ($8,284,000), $9,922,000 and $6,849,000 during 2008, 2007 and 2006, 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, 2008, the Company's hedging contracts were considered effective cash flow hedges. See Note 6 for further discussion of the Company's derivative instruments.

New Accounting Standards

In March 2008, the Financial Accounting Standards Board (the "FASB") issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities-an amendment of FASB Statement No.133" ("SFAS No. 161"). SFAS No. 161 requires enhanced disclosures about derivative and hedging activities, and is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. The Company adopted SFAS No. 161 on January 1, 2009 with no impact on its financial position or results of operations.

In December 2007, the FASB issued SFAS No. 141(R), "Business Combinations" ("SFAS No. 141(R)"). SFAS No. 141(R) replaces SFAS No. 141, "Business Combinations," and establishes principles and requirements for the recognition and measurement by an acquirer in its financial statements of the identifiable assets acquired, the liabilities assumed, and any non-controlling interest in the acquiree. The statement also establishes principles and requirements for the recognition and measurement of the goodwill acquired in the business combination or the gain from a bargain purchase and for information disclosed in its financial statements. SFAS No. 141(R) applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008.

In February 2007, the FASB issued SFAS No. 159 "The Fair Value Option for Financial Assets and Liabilities" ("SFAS No. 159"). SFAS No. 159 permits entities to choose to measure certain financial instruments and certain other items at fair value. The Company adopted SFAS No. 159 on January 1, 2008 and elected not to account for any other assets or liabilities at fair value and thus the adoption had no impact to its financial statements.

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements" ("SFAS No. 157"). SFAS No. 157 defines fair value, establishes a framework for measuring fair value under generally accepted accounting principles and expands disclosure about fair value measurements. The Company adopted SFAS No. 157 on January 1, 2008. The adoption did not have a material effect on the Company's financial position or results of operations.

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 $70.7 million in net proceeds received from the offering were primarily used to repay borrowings under the Company's credit facility.

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. On or 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 – Earnings Per Share

Basic earnings per common share is computed by dividing net income available to common stockholders by the weighted average number of shares of common stock outstanding during the periods presented. Diluted earnings per common share is determined on a weighted average basis using common shares issued and outstanding adjusted for the effect of stock options and restricted stock considered dilutive computed using the treasury stock method.

Diluted earnings per share also considers the effect of the Series B Preferred Stock by applying the "if converted" method. Under this method, the dividends applicable to the Series B Preferred Stock are added to the numerator and the Series B Preferred Stock is assumed to have been converted to common shares in the denominator. In applying the "if converted" method for the Series B Preferred Stock, conversion is not assumed in computing diluted earnings per share if the effect would be anti-dilutive.

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, 2008	Income (loss) (Numerator)	Shares (Denominator)	Per Share Amount
BASIC EPS			
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)

For the Year Ended December 31, 2007	Income (Numerator)	Shares (Denominator)	Per Share Amount
BASIC EPS			
Net income available to common stockholders	$ 39,245	48,108	$ 0.82
Effect of dilutive securities:			
Stock options	-	1,056	
Restricted stock	-	515	
DILUTED EPS	$ 39,245	49,679	$ 0.79

For the Year Ended December 31, 2006	Income (Numerator)	Shares (Denominator)	Per Share Amount
BASIC EPS			
Net income available to common stockholders	$ 23,986	47,537	$ 0.50
Effect of dilutive securities:			
Stock options	-	1,278	
Restricted stock	-	121	
DILUTED EPS	$ 23,986	48,936	$ 0.49

Restricted stock and stock options totaling 1,520,000 shares and common shares relative to the assumed conversion of the Series B preferred stock totaling 5,148,000 shares were not included in the computation of diluted earnings per share at December 31, 2008 because the inclusion would have been anti-dilutive as a result of the net loss reported for the period. Options to purchase 155,000 shares of common stock at $13.35 to $14.48 per share were outstanding during 2007 but were not included in the computation of diluted earnings per share because the options' exercise prices were greater than the average market price of the common shares. Options to purchase 153,000 shares of common stock at $11.29 to $12.54 per share were outstanding during 2006 but were not included in the computation of diluted earnings per share because the options' exercise prices were greater than the average market price of the common shares. Additionally, diluted earnings per share during 2007 did not include the assumed conversion of the Series B Preferred Stock as the effect of assuming conversion was anti-dilutive.

Note 4 – Share Based Compensation

In December 2004, the FASB issued SFAS 123 (revised 2004), "Share Based Payment," which is a revision of SFAS 123, "Accounting for Stock-Based Compensation." SFAS 123(R) supersedes APB Opinion No. 25, "Accounting for Stock Issued to Employees," and amends SFAS 95, "Statement of Cash Flows." SFAS 123(R) requires all share-based payments to employees, including grants of employee stock options and restricted stock, to be recognized in the income statement based on their estimated fair values. The Company adopted the standard during the first quarter of 2006.

The Company elected to adopt SFAS 123(R) using the "modified prospective" method in which compensation cost is recognized beginning with the effective date of January 1, 2006 using the requirements of SFAS 123(R) for all share-based payments granted after the effective date and the requirements of SFAS 123 for all unvested awards at the effective date related to awards granted prior to the effective date. The impact to net income of adopting SFAS 123(R) for the year ended December 31, 2006 was $3.7 million, or approximately $0.08 per basic and diluted share.

The Company currently has one share based compensation plan from which the Company's compensation committee may grant any of the following types of awards:

- incentive stock options as defined in Section 422 of the Code;
- nonstatutory stock options;
- stock appreciation rights;
- shares of restricted stock;
- performance units and performance shares;
- other stock-based awards.

The total amount of share-based awards available for grant under the plan is equal to the greater of (i) 15% of the number of issued and outstanding shares of the Company's common stock as of the first day of the then-current fiscal quarter, or (ii) 8,000,000 shares.

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, 2008, 2007 and 2006 is as follows (in thousands):

	Years Ended December 31,		
	2008	2007	2006
Stock options:			
Incentive Stock Options	$ 1,316	$ 1,250	$ 526
Non-Qualified Stock Options	2,729	1,869	1,344
Restricted stock	5,537	6,699	3,781
Share based compensation	$ 9,582	$ 9,818	$ 5,651

During the years ended December 31, 2008, 2007 and 2006, the Company recorded income tax benefits of approximately $3.1 million, $3.2 million and $1.9 million, respectively, related to share based compensation expense recognized during those periods. Any excess tax benefits from the vesting of restricted stock and the exercise of stock options will not be recognized in paid-in capital until the Company is in a current tax paying position. Presently, all of the Company's income taxes are deferred and the Company has substantial net operating losses available to carryover to future periods. Accordingly, no excess tax benefits have been recognized for any periods presented.

At December 31, 2008, the Company had $9.8 million of unrecognized compensation expense related to granted restricted stock and stock options. This expense will be recognized over a weighted average period of approximately two years from December 31, 2008.

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 2008, 2007 and 2006:

	Years Ended December 31,		
	2008	2007	2006
Dividend yield	0%	0%	0%
Expected volatility	54.9% - 69.8%	55.7% - 58.5%	59.0% - 62.8%
Risk-free rate	1.7% - 3.6%	4.0% - 5.1%	4.4% - 5.1%
Expected term	6 years	6 years	6 years
Forfeiture rate	5.0%	5.0%	8.4%
Stock options granted (1)	563,900	440,676	679,189
Wgtd. avg. grant date fair value per share	$ 9.45	$ 7.29	$ 6.69
Fair value of grants (1)	$ 5,330,000	$ 3,212,000	$ 4,543,000

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(1) Prior to applying estimated forfeiture rate

The following table details stock option activity during the year ended December 31, 2008:

	Number of Options	Wgtd. Avg. Exercise Price	Wgtd. Avg. Remaining Life	Aggregate Intrinsic Value (000's)
Outstanding at beginning of year	2,580,700	$6.65		
Granted	563,900	17.08		
Expired/cancelled/forfeited	(73,795)	11.90		
Exercised	(520,341)	3.65		
Outstanding at end of year	2,550,464	9.42	6.9 years	$3,551
Options exercisable at end of year	1,541,267	$5.95	5.7 years	$3,539
Options expected to vest	958,737	14.71	8.5 years	$12

The intrinsic value of options exercised during 2008, 2007 and 2006 totaled approximately $9 million, $3.5 million and $3.8 million, respectively.

The following table summarizes information regarding stock options outstanding at December 31, 2008:

Range of Exercise Price	Options Outstanding 12/31/08	Wgtd. Avg. Remaining Contractual Life	Wgtd. Avg. Exercise Price	Options Exercisable 12/31/08	Wgtd. Avg. Exercise Price
$1.53 - $3.20	663,667	4.3 years	$2.83	663,667	$2.83
$3.21 - $10.00	393,898	5.9 years	$4.45	378,565	$4.36
$10.01 - $15.00	968,824	7.8 years	$11.56	499,035	$11.31
$15.01 - $22.40	524,075	9.2 years	$17.54	-	-
	2,550,464	6.9 years	$9.42	1,541,267	$5.95

Restricted Stock

During 2006, the Company began granting shares of restricted stock in connection with its share based compensation plan. 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 grants vest 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. 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 2008:

	Number of Shares	Wgtd. Avg. Fair Value per Share
Outstanding at beginning of year	1,285,454	$11.18
Granted	326,853	16.53
Expired/cancelled/forfeited	(102,119)	11.42
Lapse of restrictions	(408,580)	11.15
Outstanding at December 31, 2008 (1)	1,101,608	$12.76

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(1) At December 31, 2008, the weighted average remaining life of restricted stock outstanding was 3.1 years and the intrinsic value of restricted stock outstanding, using the closing stock price on December 31, 2008, was $7.4 million.

Note 5 – Asset Retirement Obligations

The Company accounts for its asset retirement obligations in accordance with SFAS No. 143, "Accounting for Asset Retirement Obligations," which requires recording the fair value of an asset retirement obligation associated with tangible long-lived assets in the period incurred. Retirement obligations associated with long-lived assets included within the scope of SFAS 143 are those for which there is a legal obligation to settle under existing or enacted law, statute, written or oral contract or by legal construction under the doctrine of promissory estoppel. The Company has legal obligations to plug, abandon and dismantle existing wells and facilities that it has acquired and constructed. The following table describes the changes to the Company's asset retirement obligation liability (in thousands):

Asset retirement obligation at January 1, 2008	$ 17,451
Liabilities incurred during 2008	9,464
Liabilities settled during 2008	(20,876)
Accretion expense	1,317
Revisions in estimates	18,277
Asset retirement obligation at December 31, 2008	25,633
Less: current portion of asset retirement obligation	(8,590)
Long-term asset retirement obligation	$ 17,043

Note 6 – Derivatives

Estimating the fair value of derivative instruments requires valuation calculations incorporating estimates of future NYMEX prices, discount rates and price movements. As a result, the Company calculates the fair value of its 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. 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.

The Company's credit agreement requires that the counterparties to the Company's 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 the Company's existing hedge contracts are JPMorgan and Calyon, both of which are lenders under the credit agreement. To the extent the Company enters into additional hedge contracts, it expects that certain lenders under the credit agreement would serve as counterparties.

As of December 31, 2008, the Company 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:			
January - June 2009	Swap	20,000 Mmbtu	$5.62
2009	Swap	10,000 Mmbtu	$7.46
2009	Costless Collar	30,000 Mmbtu	$8.75 - 11.38
Crude Oil:			
2009	Costless Collar	400 Bbls	$100.00 - 168.50

At December 31, 2008, the Company recognized an asset of $40.6 million related to the estimated fair value of these derivative instruments. Based on estimated future commodity prices as of December 31, 2008, the Company would realize a $25.6 million gain, net of taxes, as an increase to oil and gas sales during the next 12 months. These gains are expected to be reclassified based on the schedule of oil and gas volumes stipulated in the derivative contracts.

As defined in SFAS No. 157, 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. SFAS 157 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 SFAS 157, the Company classified its commodity derivatives based upon the data used to determine fair value. The Company's derivative instruments at December 31, 2008 were in the form of swaps and 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, 2008 (in thousands):

	Fair Value Measurements Using		
Instrument	Quoted Prices in Active Markets (Level1)	Significant Other Observable Inputs (Level2)	Significant Unobservable Inputs (Level3)
Commodity Derivatives	-	$ 40,571	-

The following table sets forth a reconciliation of changes in the fair value of the Company's commodity derivative asset (liability) classified as Level 3 in the fair value hierarchy (in thousands):

	Year Ended December 31, 2008
Balance at beginning of period	$ (691)
Total gains or losses (realized or unrealized):	
Included in earnings	(8,284)
Included in other comprehensive income	41,262
Purchases, issuances and settlements	8,284
Transfers in and out of Level 3 (1)	(40,571)
Balance at end of period	$ -

(1) During 2008, the Company began deriving the fair value of its derivative instruments using an independent third-party's valuation model that utilizes market-corroborated inputs that are observable over the term of the derivative contract.

Note 7 - Debt

During 2005, the Company and PetroQuest Energy, L.L.C. issued $150 million in principal amount of 10 3/8% Senior Notes due 2012 (the "Notes"). The Notes are guaranteed by the significant subsidiaries of the Company and PetroQuest Energy, L.L.C. The aggregate assets and revenues of subsidiaries not guaranteeing the Notes constituted less than 3% of the Company's consolidated assets and revenues at and for the years ended December 31, 2008, 2007 and 2006.

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 May 15 and November 15. At December 31, 2008, $1.9 million had been accrued in connection with the May 15, 2009 interest payment and the Company was in compliance with all of the covenants under the Notes.

On October 2, 2008, the Company and PetroQuest Energy, L.L.C. (the "Borrower") entered into the Credit Agreement (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. The Credit Agreement matures on February 10, 2012; provided, however, if on or prior to such date the Company prepays or refinances, subject to certain conditions, the Notes, the maturity date will be extended to October 2, 2013. As of December 31, 2008, the Company had $130 million of borrowings outstanding under (and no letters of credit issued pursuant to) the Credit Agreement.

The borrowing base under the Credit Agreement is based upon the valuation as of January 1 and July 1 of each year of the reserves attributable to the Company's oil and gas properties. The initial borrowing base is fixed at $150 million until the first borrowing base redetermination, which is scheduled to occur by March 31, 2009. The Company or the lenders may request two additional borrowing base redeterminations each year. Each time the borrowing base is to be redetermined, 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.

At December 31, 2008, the borrowing base under the Credit Agreement exceeded the Company's outstanding borrowings by $20 million; however, as a result of the declines in commodity prices since the establishment of the borrowing base, the Company anticipates that its next regularly scheduled borrowing base redetermination, which is scheduled to occur by March 31, 2009, will result in a borrowing base of less than $150 million. As a result of the redetermination, the Company may be unable to borrow any additional funds under the Credit Agreement, and if the revised borrowing base is less than $130 million, the Company will be obligated to repay the amount by which its aggregate credit exposure under the Credit Agreement exceeds the revised borrowing base within forty-five days after the revised borrowing base is determined. At December 31, 2008, the Company had cash and cash equivalents of approximately $24 million that the Company believes would be sufficient to repay amounts that may be required as the result of the redetermined borrowing base.

The indenture governing the Notes also limits the Company's ability to incur indebtedness under the Credit Agreement. Under the indenture the Company will not be able to incur additional indebtedness under the Credit Agreement in excess of 20% of its adjusted consolidated net tangible assets (as defined in the indenture). That calculation is based primarily on the valuation of the Company's estimated reserves of oil and natural gas using year-end commodity prices. Until recalculated, the Company will not be able to incur new indebtedness under the Credit Agreement in excess of $93 million. While the indenture limits the amount of new indebtedness that may be incurred under the Credit Agreement, it does not restrict the amount of that indebtedness that may be outstanding under the Credit Agreement. Therefore, even though the amount of indebtedness under the Credit Agreement at December 31, 2008 exceeds 20% of the adjusted consolidated net tangible assets, the Company is not required by the indenture to reduce the amount currently outstanding.

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 0.0% to 0.75% depending on borrowing base usage) or the adjusted LIBO rate ("Eurodollar") plus a margin (based on a sliding scale of 1.5% to 2.25% depending on borrowing base usage). However, for the first six months of the Credit Agreement, the margin will be 0.5% for ABR loans and 2.0% for Eurodollar loans. The alternate base rate is equal to the higher of the JPMorgan Chase prime rate or the Federal Funds Effective Rate plus 0.5% per annum, and 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 Borrower) are quoted, as adjusted for statutory reserve requirements for Eurocurrency liabilities. Outstanding letters of credit will be charged a participation fee at a per annum rate equal to the margin applicable to Eurodollar loans, a fronting fee and customary administrative fees.

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, 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, 2008, the Company was in compliance with all of the covenants contained in the Credit Agreement.

Note 8 - Related Party Transactions

Three of the Company's 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, one of the Company's directors, is a working interest owner 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 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. During the year ended December 31, 2007, in their capacities as working interest owners or overriding royalty interest owners, revenues, net of costs were disbursed to Messrs. Goodson, Green and Stover, or their affiliates, in the amounts of $2,519,300, $1,267,100 and $62,200, respectively, and with respect to the working interests of Mr. Nordberg, revenues exceeded costs by $3,700. During the year ended December 31, 2006, revenues, net of costs were disbursed to Messrs. Goodson, Green and Stover, or their affiliates, in the amounts of $253,400, $896,200 and $98,900, respectively, and with respect to the working interests of Mr. Nordberg, revenues exceeded costs by $55,000. 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 2008.

Periodically, the Company charters private aircraft for business purposes. During 2008 and 2007, the Company paid approximately $6,700 and $170,000, 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.

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, 2008, the Company's joint interest billing receivable included approximately $29,000, 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, 2008.

Note 9 – 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 prices of oil and natural gas declined significantly during the third and fourth quarters of 2008. At December 31, 2008, the prices used in computing the estimated future net cash flows from the Company's proved reserves, including the effect of hedges in place at December 31, 2008, averaged $4.86 per Mcfe and $45.21 per barrel. As a result of lower prices, and their negative impact on certain of the Company's proved reserves and estimated future net cash flows, the Company recognized ceiling test write-downs of $266.2 million during 2008. Utilizing the Company's cash flow hedges in place at December 31, 2008 reduced the ceiling test write-down at December 31, 2008 by approximately $45 million.

Note 10 - 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,		
	2008	2007	2006
Acquisition costs:			
Proved	$ 3,014	$ 1,253	$ 7,515
Unproved	58,826	32,833	12,744
Exploration costs:			
Proved	149,811	104,669	70,526
Unproved	6,048	15,908	7,457
Development costs	118,891	71,973	61,643
Capitalized general and administrative and interest costs	21,181	14,061	10,841
Total costs incurred	$ 357,771	$ 240,697	$ 170,726

	For the Year-Ended December 31,		
Accumulated depreciation, depletion and amortization (DD&A)	2008	2007	2006
Balance, beginning of year	$ (432,530)	$ (314,869)	$ (210,774)
Provision for DD&A	(131,348)	(116,384)	(82,928)
Ceiling test writedown	(266,156)	-	-
Sale of proved properties and other	(2,256)	(1,277)	(21,167)
Balance, end of year	$ (832,290)	$ (432,530)	$ (314,869)
DD&A per Mcfe	$ 3.89	$ 3.70	$ 3.23

At December 31, 2008 and 2007, unevaluated oil and gas properties totaled $119,847,000 and $80,297,000, respectively, and were not subject to depletion. Unevaluated costs at December 31, 2008 included $6,048,000 of costs related to 26 exploratory wells in progress at year-end. These costs will be transferred to evaluated oil and gas properties and depreciated during 2009 upon the completion of drilling. At December 31, 2007, unevaluated costs included $15,908,000 related to exploratory wells in progress. All of these costs were transferred to evaluated oil and gas properties during 2008. The Company capitalized $10,525,000, $6,539,000 and $4,650,000 of interest during 2008, 2007 and 2006, respectively. Of the total unevaluated oil and gas property costs at December 31, 2008, $75,399,000, or 63%, was incurred in 2008, $31,332,000 was incurred in 2007 and $13,116,000 was incurred in prior years. The Company expects that the majority of the unevaluated costs at December 31, 2008 will be evaluated within the next three years.

Note 11 - Income Taxes

The Company follows the provisions of SFAS No. 109, "Accounting For Income Taxes," 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. An analysis of the Company's deferred taxes follows (amounts in thousands):

	December 31, 2008	December 31, 2007
Net operating loss carryforwards	$ 13,301	$ 31,542
Percentage depletion carryforward	2,619	2,928
Alternative minimum tax credit	144	105
Contributions carryforward and other	156	109
Temporary differences:		
Oil and gas properties - full cost	(30,207)	(104,252)
Hedges	(15,011)	255
Compensation expense	153	153
Deferred tax liability	$ (28,845)	$ (69,160)

At December 31, 2007, the Company had an operating loss carryforward of $84,789,000. The Company made certain elections in its 2007 tax return, prepared during 2008, to utilize tax attributes expiring during the 2007 tax year. As a result, the Company's operating loss carryforward as reported on its 2007 tax return was $45,661,000. The adjustment to the Company's operating loss carryforward was offset by an increase to the temporary difference related to oil and gas properties and thus resulted in no change to the Company's net deferred tax position at December 31, 2007.

At December 31, 2008, the Company had $35,755,000 of operating loss carryforwards. If not utilized, approximately $3,648,000 of such carryforwards would expire in 2009 and the remainder would completely expire by the year 2026. The Company has available for tax reporting purposes $7,483,000 in statutory depletion deductions that may be carried forward indefinitely.

Income tax expense (benefit) for each of the years ended December 31, 2008, 2007 and 2006 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, 2008	2007	2006
Amount computed using the statutory rate	$ (53,389)	$ 22,499	$ 13,507
Increase (reduction) in taxes resulting from:			
State & local taxes	(3,357)	1,414	849
Percentage depletion carryforward	310	(860)	(74)
Non-deductible stock option expense (1)	490	462	195
Other	365	149	127
Income tax expense (benefit)	$ (55,581)	$ 23,664	$ 14,604

(1) Relates to compensation expense recognized on the vesting of Incentive Stock Options

Note 12 - Commitments and Contingencies

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

Lease Commitments

The Company has operating leases for office space and equipment, which expire on various dates through 2013.

Future minimum lease commitments as of December 31, 2008 under these operating leases are as follows (in thousands):

2009	$ 1,070
2010	1,039
2011	893
2012	750
2013	63
Thereafter	-
	$ 3,815

From July 2003 through April 2006, the Company subleased office space to third parties. For the year ended December 31, 2006, the Company received $28,000 relative to subleased office space. Total rent expense under operating leases, net of amounts received under sublease arrangements, was approximately $965,000, $910,000 and $752,000 in 2008, 2007 and 2006, respectively.

Note 13 - Oil and Gas Reserve Information - Unaudited

The Company's net proved oil and gas reserves at December 31, 2008 have been estimated by independent petroleum engineers in accordance with guidelines established by the Securities and Exchange Commission. Accordingly, the following reserve estimates are based upon existing economic and operating conditions at the respective dates.

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

During 2008, the Company increased its estimated proved reserves by 18%. This increase was primarily due to the Company's continued drilling success in Oklahoma and Arkansas. The Company added approximately 57 Bcfe of proved reserves in these areas during 2008 as a result of drilling 126 gross wells with a 100% success rate. Offsetting the discoveries in Oklahoma and Arkansas were negative reserve revisions primarily caused by the impact of lower oil and gas prices at December 31, 2008. Overall, the Company had a 96% drilling success rate during 2008 on 150 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	Natural Gas and NGL in MMcfe
Proved reserves as of December 31, 2005	3,642	109,115
Revisions of previous estimates	(197)	2,744
Extensions, discoveries and other additions	773	34,498
Purchase of producing properties	-	-
Sale of producing properties	(792)	(6,676)
Production	(695)	(21,528)
Proved reserves as of December 31, 2006	2,731	118,153
Revisions of previous estimates	109	14,047
Extensions, discoveries and other additions	366	37,590
Purchase of producing properties	234	173
Sale of producing properties	(18)	(2,529)
Production	(1,080)	(24,966)
Proved reserves as of December 31, 2007	2,342	142,468
Revisions of previous estimates	(21)	(11,126)
Extensions, discoveries and other additions	499	69,800
Purchase of producing properties	62	1,047
Sale of producing properties	-	(295)
Production	(681)	(29,708)
Proved reserves as of December 31, 2008	2,201	172,186
Proved developed reserves		
As of December 31, 2006	2,528	81,487
As of December 31, 2007	2,070	95,639
As of December 31, 2008	2,030	124,020

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, 2008	2007	2006
Future cash flows	$ 889,732	$ 1,155,236	$ 786,829
Future production costs	(275,117)	(240,849)	(168,037)
Future development costs	(148,167)	(134,993)	(102,778)
Future income taxes	(14,479)	(143,683)	(70,615)
Future net cash flows	451,969	635,711	445,399
10% annual discount	(137,182)	(188,453)	(112,566)
Standardized measure of discounted future net cash flows	$ 314,787	$ 447,258	$ 332,833

Changes in Standardized Measure	Year Ended December 31, 2008	2007	2006
Standarized measure at beginning of year	$ 447,258	$ 332,833	$ 483,412
Sales and transfers of oil and gas produced, net of production costs	(259,950)	(206,477)	(152,550)
Changes in price, net of future production costs	(172,214)	153,961	(221,118)
Extensions and discoveries, net of future production and development costs	147,089	95,850	124,138
Changes in estimated future development costs, net of development costs incurred during this period	36,567	12,014	18,016
Revisions of quantity estimates	(25,037)	66,025	5,199
Accretion of discount	54,065	38,431	63,973
Net change in income taxes	80,988	(41,913)	104,841
Purchase of reserves in place	1,944	14,108	-
Sale of reserves in place	(1,378)	(9,293)	(70,765)
Changes in production rates (timing) and other	5,455	(8,281)	(22,313)
Standardized measure at end of year	$ 314,787	$ 447,258	$ 332,833

The weighted average prices of oil and gas used for the above tables at December 31, 2008, 2007 and 2006 were $41.53, $96.83 and $59.85 per barrel, respectively, and $4.64, $6.52 and $5.28 per Mcfe, respectively. The Company's cash flow amounts include a reduction for estimated plugging and abandonment costs that have also been reflected as a liability on the balance sheet at December 31, 2008 and 2007, in accordance with SFAS No. 143.

Note 14 – 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
2008:				
Revenues	$ 76,550	$ 92,868	$ 78,276	$ 66,264
Income (loss) from operations (1)	24,719	36,793	28,847	(242,900)
Net income (loss) available to common stockholders (1)	14,161	21,775	16,758	(154,794)
Earnings (loss) per share:				
Basic	$ 0.29	$ 0.45	$ 0.34	$ (3.14)
Diluted	$ 0.28	$ 0.41	$ 0.32	$ (3.14)
2007:				
Revenues	$ 63,527	$ 66,556	$ 65,169	$ 67,082
Income from operations	17,351	15,504	12,908	18,520
Net income available to common stockholders	10,814	9,630	7,964	10,837
Earnings per share:				
Basic	$ 0.23	$ 0.20	$ 0.16	$ 0.22
Diluted	$ 0.22	$ 0.19	$ 0.16	$ 0.22

(1) Income from operations and net income available to common stockholders reported during the three months ended September 30, 2008 include a gain on the sale of gas gathering systems totaling $26.7 million (see Note 1). Loss from operations and net loss available to common stockholders reported during the three months ended December 31, 2008 include a non-cash ceiling test write-down of $246.8 million (see Note 9).

Exhibit 21.1

Subsidiaries of PetroQuest Energy, Inc.

Name	Jurisdiction
PetroQuest Energy, L.L.C.[1]	Louisiana
PetroQuest Oil and Gas, L.L.C.[1]	Louisiana
TDC Energy LLC[1]	Louisiana
Pittrans, Inc.[2]	Oklahoma
Sea Harvester Energy Development Company, L.L.C.[3]	Louisiana

[1] 100% owned by PetroQuest Energy, Inc.
[2] 100% owned by PetroQuest Energy, L.L.C.
[3] 92% owned by TDC Energy LLC

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. 333-131955, 333-124746, 333-42520 and 333-89961 and Form S-8 Nos. 333-134161, 333-102758, 333-88846, 333-67578, 333-52700, 333-65401 and 333-151296) of PetroQuest Energy, Inc. and in the related Prospectuses of our reports dated February 26, 2009, 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, 2008.

/s/ Ernst & Young LLP
New Orleans, Louisiana
February 26, 2009

Exhibit 23.2

Consent of Ryder Scott Company, L.P.

We hereby consent to the incorporation by reference in this Annual Report on Form 10-K prepared by PetroQuest Energy, Inc. (the "Company") for the year ending December 31, 2008, and to the incorporation by reference thereof into the Company's previously filed Registration Statements on Form S-3 (File Nos. 333-131955, 333-124746, 333-42520 and 333-89961) and Form S-8 (File Nos. 333-134161, 333-102758, 333-88846, 333-67578, 333-52700, 333-65401 and 333-151296), of information contained in our reports 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, 2008. We further consent to references to our firm under the headings "Risk Factors" and "Oil and Gas Reserves."

/s/ RYDER SCOTT COMPANY, L.P.
Houston, Texas
February 26, 2009

Exhibit 23.3

Consent of Netherland, Sewell and Associates, Inc.

We hereby consent to the incorporation by reference in this Annual Report on Form 10-K prepared by PetroQuest Energy, Inc. (the "Company") for the year ending December 31, 2008, and to the incorporation by reference thereof into the Company's previously filed Registration Statements on Form S-3 (File Nos. 333-131955, 333-124746, 333-42520 and 333-89961) and Form S-8 (File Nos. 333-134161, 333-102758, 333-88846, 333-67578, 333-52700, 333-65401 and 333-151296), of information contained in our reports 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, 2008. We further consent to references to our firm under the headings "Risk Factors" and "Oil and Gas Reserves."

NETHERLAND, SEWELL AND ASSOCIATES, INC.
By: /s/ C.H. (Scott) Rees III, P.E.
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer
Dallas, Texas
February 27, 2009

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 26, 2009

Exhibit 31.2

I, W. Todd Zehnder, certify that:

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

7. 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;

8. 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;

9. 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

10. 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/ W. Todd Zehnder
W. Todd Zehnder
Chief Financial Officer
February 26, 2009

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, 2008 (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 26, 2009

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, 2008 (the “Report”), as filed with the Securities and Exchange Commission on the date hereof, I, W. Todd Zehnder, 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/ W. Todd Zehnder
W. Todd Zehnder
Chief Financial Officer
February 26, 2009

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.

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

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

Art M. Mixon
Executive Vice President—Exploration and Production

Mark K. Stover
Executive Vice President—Corporate Development

W. Todd Zehnder
Executive Vice President, Chief Financial Officer, and Treasurer

J. Bond Clement
Senior Vice President—Chief Accounting Officer

Stephen H. Green
Senior Vice President—Exploration

Dalton F. Smith III
Senior Vice President—Business Development

James S. Blair
Vice President—Business Development

Thomas P. Murphy
Vice President—Engineering

Patrick A. Brazan
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

Onebane Law Firm
Lafayette, Louisiana 70502

Porter & Hedges, L.L.P.
Houston, Texas 77002

ANNUAL MEETING

The Company's Annual Meeting of Stockholders will be held at 9:00 a.m. CDT on May 13, 2009, at the City Club at River Ranch, 221 Elysian Fields Drive, Lafayette, Louisiana 70508.

FORM 10-K

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

COMMON STOCK LISTING

Listed on NYSE as PQ

PQ
LISTED
NYSE

PetroQuest Energy, Inc.

400 East Kaliste Saloom Road, Suite 6000

Lafayette, Louisiana 70508

Telephone: (337) 232-7028 Fax: (337) 232-0044

www.petroquest.com