PetroQuest Energy, Inc. Annual Report 2004

ENERGY

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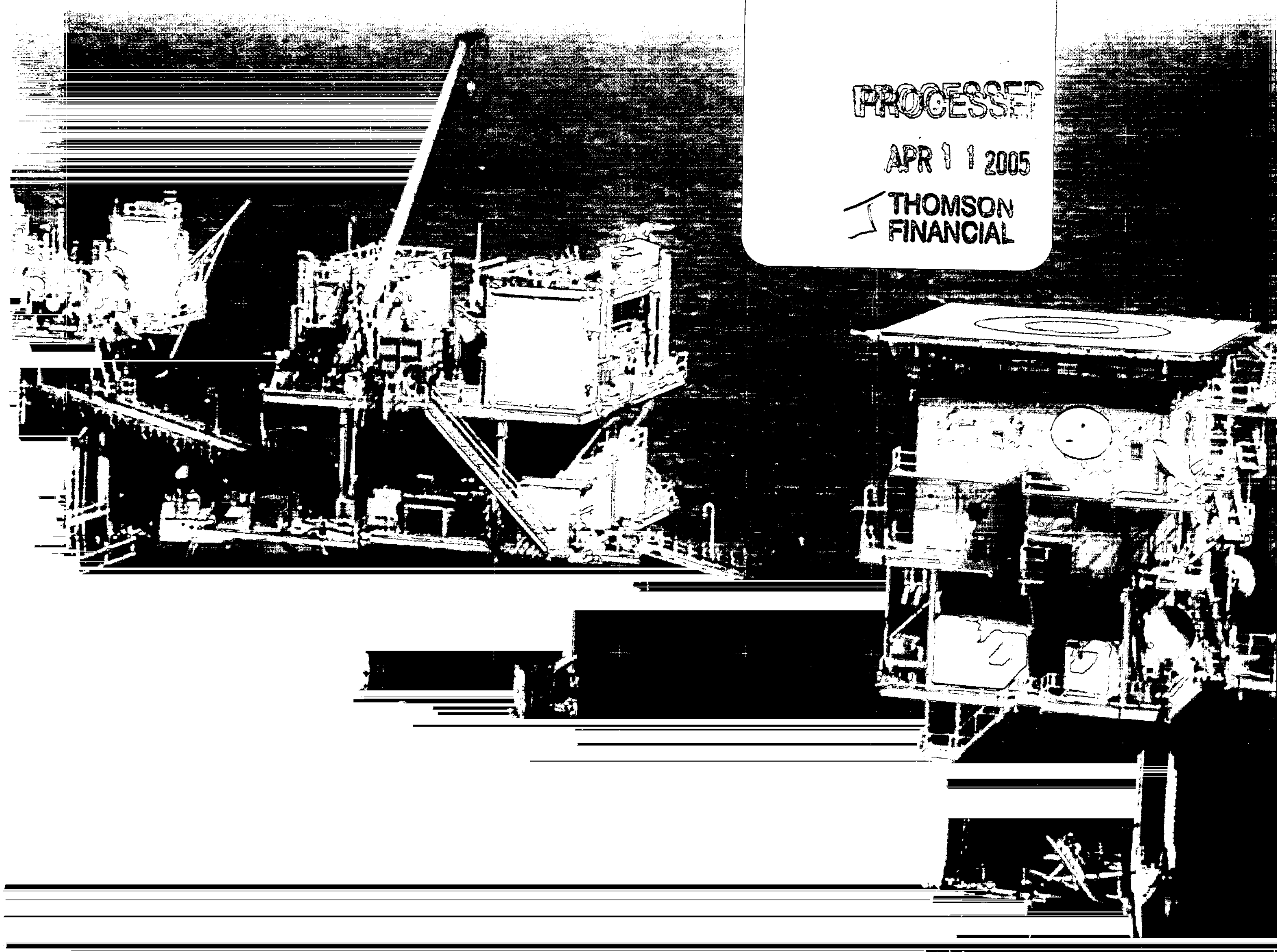


Corporate Profile 1

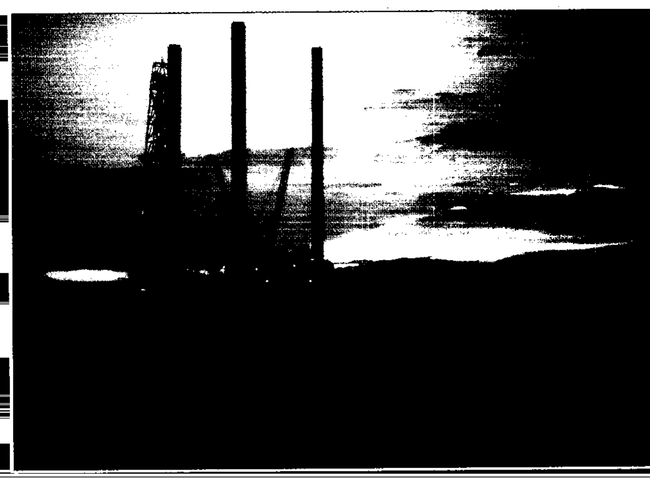
Financial and Operational Highlights 2

Letter to Stockholders 3

Areas of Operation 6

Form 10-K 9

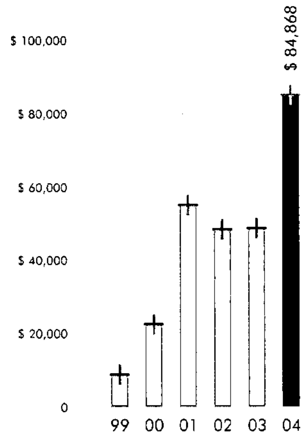
Corporate Information .... Inside Back Cover



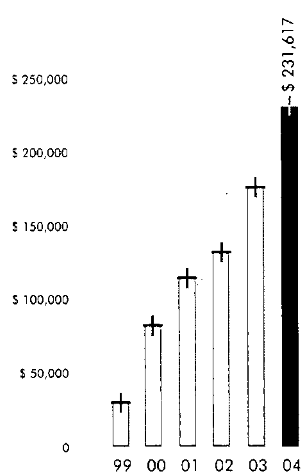
Approximately 70% of PetroQuest Energy's production comes from the Gulf of Mexico.

The Annual Meeting of Stockholders of PetroQuest Energy, Inc. will be held on May 12, 2005, at 9:00 a.m. at the City Club at River Ranch, 221 Elysian Fields Drive, Lafayette, Louisiana 70508.

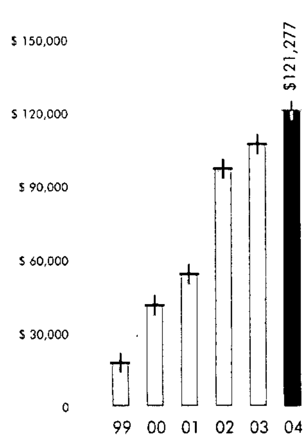
About the cover: Since acquiring its 100% interest in Ship Shoal 72, PetroQuest has completed all 15 wells drilled, increasing production to 16 MMcfe per day during 2004.



Total Revenues
$ in thousands
5-Year CAGR 58%



Total Assets
$ in thousands
5-Year CAGR 51%



Stockholders' Equity
$ in thousands
5-Year CAGR 46%

Corporate Profile

PetroQuest Energy is an energy company involved in the acquisition, exploration, exploitation and development of natural gas and crude oil. We operate substantially all of our assets in three of America's most prolific producing regions – the onshore and offshore Gulf Coast Basin, East Texas and the Arkoma Basin of Oklahoma. We work these areas because there are many opportunities to develop high quality reserves, ensuring steady growth in future production and cash flow profiles. Since 1998, the Company's reserves have grown at a 40% compound annual growth rate (CAGR), production grew at a 43% CAGR and cash flow rose at a 108% CAGR.

PetroQuest's portfolio approach in managing our capital expenditure program is a catalyst for our very respectable compound annual growth rate in key metrics. The Company dedicates approximately 65% of its annual capital program to low-to medium-risk projects, complemented by a deep inventory of exploration projects. Since 1998, PetroQuest added 189.6 Bcfe of reserves through its drilling and acquisition activities alone, while producing 59.4 Bcfe, a 319% reserve replacement ratio.

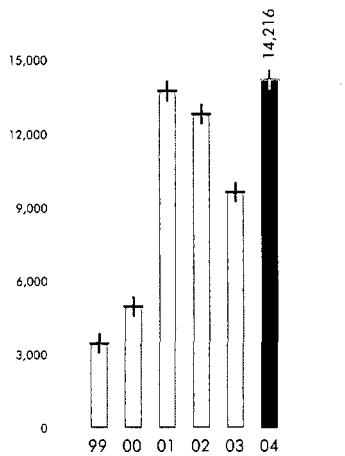
PetroQuest's management team and staff are guided by a four-tiered growth strategy:

+ use in-house experience and advanced technologies to develop a multi-risked, multi-project exploration and development program;
+ augment the exploration and development activity with acquisitions that deliver immediate shareholder-friendly cash flows and offer long-term exploitation projects for increasing production;
+ balance the use of equity and long-term debt to execute the operating strategy; and
+ over-deliver on our promises.

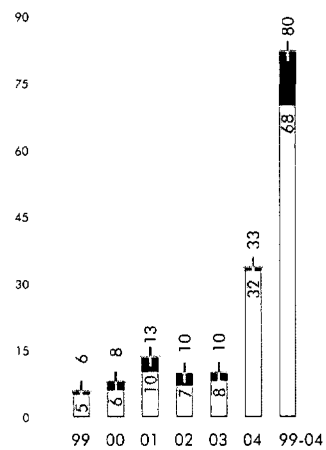
PetroQuest Energy, Inc. and its 48 stockholder employees are primarily based in Lafayette, Louisiana, with an exploration office in Houston. As a group, the Board of Directors, management and staff own approximately 20% of the 44.6 million shares outstanding. Approximately 500,000 of PetroQuest's common shares trade each day on the NASDAQ National Market System under the ticker PQUE. The Company's common shares are widely held with approximately 40% owned by some of America's top institutional money managers.

	2000	2001	2002	2003	2004					4-Year
	nnual	Annual	Annual	Annual	Q1	Q2	Q3	Q4	Annual	CAGR
roduction										
atural Gas, MMcf	3,984	9,025	7,765	5,193	2,162	2,160	2,481	2,502	9,305	24%
rude Oil, MBbl	161	791	929	745	178	246	219	175	818	50%
atural Gas, MMcfe	4,948	13,774	13,340	9,660	3,233	3,637	3,795	3,552	14,216	30%
000s, except per share amounts										
inancial										
tal Revenues	$ 22,561	$ 35,342	$ 48,238	$ 48,688	$ 18,202	$ 21,497	$ 22,572	$ 22,597	$ 84,868	39%
perating Cash Flow	$ 22,835	$ 40,869	$ 29,178	$ 33,163	$ 10,220	$ 13,317	$ 25,935	$ 20,838	$ 70,310	32%
et Income	$ 9,924	$ 11,645	$ 2,307	$ 3,640	$ 3,172	$ 4,237	$ 3,940	$ 4,999	$ 16,348	13%
er Common Share:										
asic	$ 0.37	$ 0.37	$ 0.06	$ 0.08	$ 0.07	$ 0.10	$ 0.09	$ 0.11	$ 0.37	nm
iluted	$ 0.35	$ 0.34	$ 0.06	$ 0.08	$ 0.07	$ 0.09	$ 0.08	$ 0.11	$ 0.35	nm

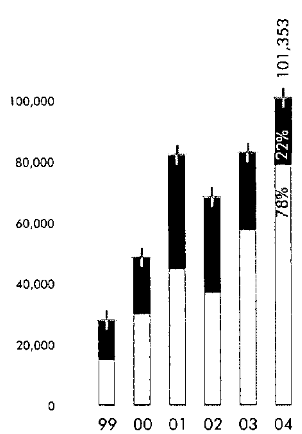
	[illegible]	2000	2001	2002	2003	2004	5-Year CAGR
eserves							
atural Gas, MMcf	15,128	30,135	44,944	37,137	57,793	79,069	39%
rude Oil, MBbl	2,194	3,115	6,213	5,258	4,245	3,714	11%
atural Gas, MMcfe	28,292	48,824	82,225	68,685	83,263	101,353	29%
ercent Developed	31%	67%	55%	62%	67%	68%	nm
ercent Natural Gas	53%	62%	55%	54%	69%	78%	nm
ercent Offshore	52%	57%	80%	84%	55%	59%	nm
uture Gross Revenues, $ 000s	$ 92,788	$ 391,078	$ 234,736	$ 337,776	$ 460,073	$ 622,940	46%
EC PV-10, Before Taxes, $ 000s	$ 43,069	$ 256,867	$ 88,230	$ 166,048	$ 214,365	$ 326,267	50%
Commodity Prices							
etroQuest Realized, Natural Gas, $/Mcf	$ 2.33	$ 4.38	$ 3.86	$ 3.20	$ 5.14	$ 5.99	
enry Hub Cash Market Average, Natural Gas, $/Mcf	2.27	4.15	3.96	3.32	5.49	6.15	Source: Bloomberg
etroQuest Realized, Crude Oil, $/Bbl	18.45	29.94	25.49	25.07	28.47	35.31	
WTI (Cushing) Spot Average, Crude Oil, $/Bbl	19.30	30.35	25.84	26.17	31.06	41.48	Source: Bloomberg
etroQuest Realized, Natural Gas Equivalent, $/Mcfe	$ 2.46	$ 4.50	$ 3.99	$ 3.61	$ 4.96	$ 5.95	
tatistics							
eserve Replacement, Excluding Revisions, %	486%	473%	385%	211%	384%	220%	
-Year Reserve Replacement, Excluding Revisions, %						319%	
inding & Development Costs, Excluding Revisions, $/Mcfe	$ 0.77	$ 1.75	$ 1.27	$ 2.31	$ 1.43	$ 2.77	
-Year Finding & Development Costs, Excluding Revisions, $/Mcfe						$ 1.87	
er Unit Analysis, $/Mcfe							
evenues	2.46	4.51	3.99	3.61	4.96	$5.97	19%
ease Operating Expense and Production Taxes	0.88	0.76	0.60	0.79	1.07	1.04	3%
General and Administrative	0.47	0.66	0.35	0.38	0.46	0.44	(1)%
Gross Margin	1.11	3.08	3.06	2.44	3.43	4.47	32%
DD&A	1.29	1.29	1.68	2.11	2.81	2.49	14%
et Income	(0.09)	2.01	0.85	0.17	0.38	1.15	nm



Annual Production
MMcfe
5-Year CAGR 33%



Drilling Activity
■ Total Gross Wells Drilled
□ Total Gross Wells Completed



Total Proved Reserves
MMcfe
5-Year CAGR 29%
■ Oil
□ Gas

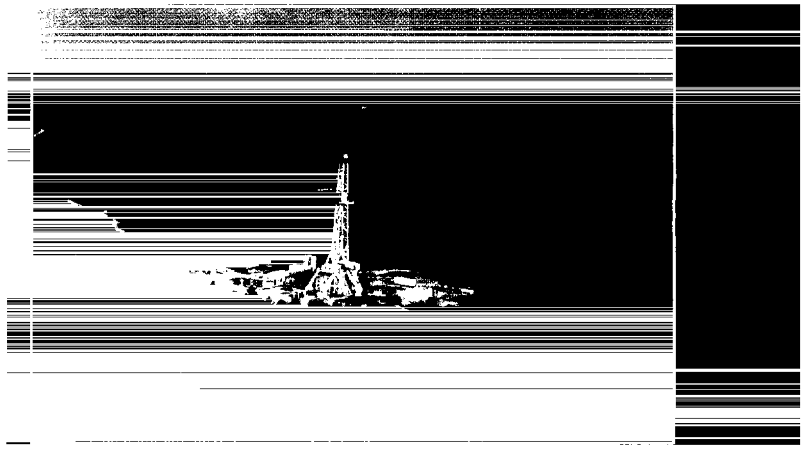
Letter to Stockholders

After conservatively managing our way through 2003, our unwavering determination led to PetroQuest's best year ever recorded. In last year's letter, I outlined how we would use our time-tested experience and commitment to excellence to return PetroQuest to a familiar path of growth: production growth, reserve growth, asset growth, stockholders' equity growth. We forecasted production would be higher in 2004 than 2003. Annual production was a Company-record 14.2 Bcfe, a 47% increase. We outlined how we would tweak our operating strategy to put more capital to work to drill more wells and realize an increase in reserves. Reserves expanded by 22%, reaching 101.4 Bcfe. We spent a Company-record $86.4 million to drill and complete 32 gross wells and acquire reserves. We challenged the entire organization to renew their efforts, apply fresh approaches to how we perform our day-to-day functions and remain focused on our single-most important goal: growing stockholder value. Our share price rose 56% in 2004. Since 1998, PetroQuest's stock price has increased at a 35% compound annual rate. A $100,000 investment in PetroQuest in 1998 would today be worth $866,461.

Our Disciplined Approach Set New Milestones

Throughout our history, growth and the value realized by stockholders has come from the consistent application of a strategy that builds upon our successful exploration, exploitation and development drilling programs, augmented with strategic acquisitions. You can measure the growth of a young U.S. oil and gas company by noting the passing of new milestones. In delivering sharply improved 2004 results, we set several new marks:

+ Proved reserves of 101.4 Bcfe
+ Annual production of 14.2 Bcfe
+ Total revenues of $84.9 million
+ Operating cash flow of $70.3 million
+ Net income of $16.3 million
+ Capital expenditures of $86.4 million
+ Total assets of $231.7 million
+ Stockholders' equity of $121.3 million



During 2005, PetroQuest Energy has more than 50 well locations to drill on its long-lived acreage in East Texas and Southeast Oklahoma.

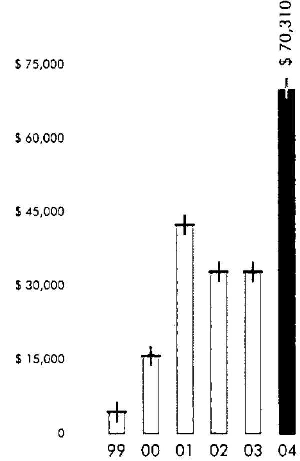
Over the last few years, we've witnessed a historic change in oil and gas prices. Gone are the days when natural gas sold for less than a gallon of gasoline and crude oil was priced according the whim of a select few. The world is a far more complex and dangerous place, and yet, economies foreign and domestic are expanding and demanding more energy. The world's population and demand for energy is growing not shrinking. As we see it, crude oil and natural gas are still the long-term preferred forms of hydrocarbon-based energy sources to meet the world's seemingly insatiable appetite for energy. Until the U.S. enacts a real energy policy, the domestic oil and gas sector will have a very difficult time developing enough resources to keep pace with the growing consumption demand. We cannot realistically expect the United States will be energy self-sufficient in our lifetimes, or our children's, or grandchildren's. What we can hope for is that our government leaders will pay attention to the many ways the domestic crude oil and natural gas industry can improve upon the many opportunities they can take to make the United States less dependent on foreign sources of energy.

Between 2001 and 2004, natural gas prices at the Henry Hub, the most watched pricing point in the world for natural gas, moved from $4.07 per Mcf to $5.85 per Mcf, a 44% change. West Texas Intermediate, the world's benchmark for light, sweet crude, averaged $40 per barrel in 2004, up 54% from the $25.92 average in 2001. Some prognosticators predict the prices of both commodities will drop in 2005. However, the markets remain strong as the average NYMEX strip price for natural gas is $6.47 per Mcf through January 2007 and $44.05 per barrel through December 2010.

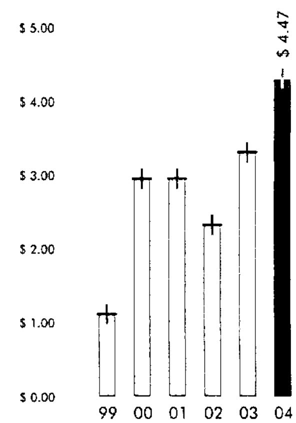
Our 2005 budget includes drilling nearly 75 wells from our existing inventory. We drilled 33 in 2004, completing 32, a 97% success rate. During the period 1999 through 2004, PetroQuest completed 68 of the 80 wells drilled. Our prior success along with planned 2005 activity should increase our 2005 production to a record level.

To PetroQuest Energy, the achievement of producing more oil and natural gas in 2004 than we had on the books in 1998 is an enormously significant benchmark. In 2004, PetroQuest undertook its largest ever capital expenditure program, investing $86.4 million, 27% of which was related to producing property acquisitions.

We continually look for opportunities to enhance our position in core areas, and we intend to pursue strategic acquisitions which are within our operating and financial parameters. Those strategic acquisitions serve as a fuel source for our growth. An ideal acquisition candidate is one which offers immediate production, a long-term drilling inventory with multiple producible and multiple-risked horizons, and



Net Cash Provided by Operating Activities
$ in thousands
5-Year CAGR 74%



Gross Margin, $/Mcfe
6-Year Gross Margin ROI[1] 239%

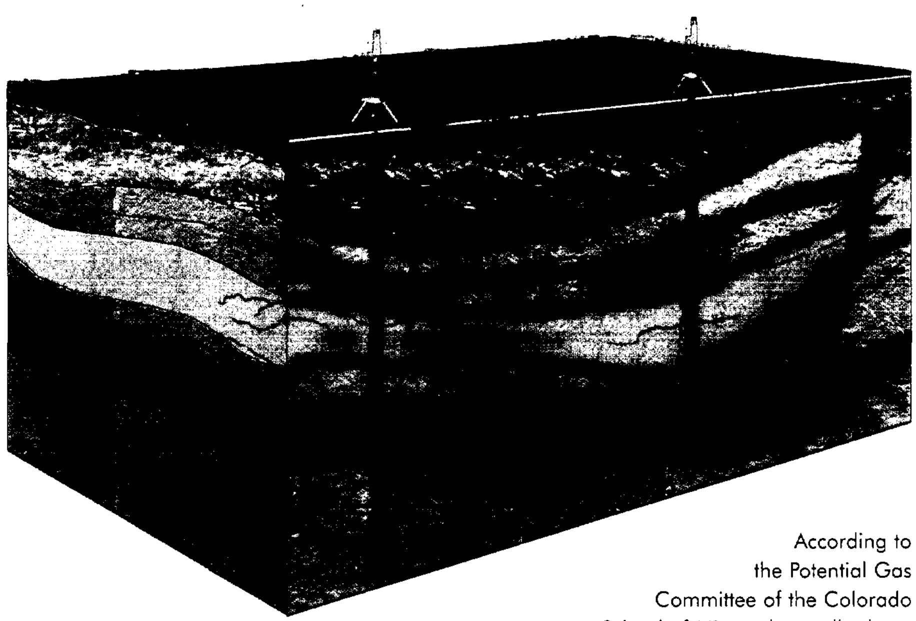
[1] Weighted average Gross Margin ROI is a 6-year weighted average gross margin divided by a 6-year weighted average F&D, excluding revisions.

complementary or follow-on opportunities to add to the property's production base or acreage position. We believe we grow best in areas where we have operating experience and existing production. This way we are able to increase reserves and production while lowering costs.

Over the course of the past two years, PetroQuest set a goal to add long-lived assets, diversifying outside of its traditional Gulf Coast operating base. In December 2003, PetroQuest announced its largest acquisition ever when it purchased proved, producing properties containing 29 Bcfe in the East Texas Carthage Field for $23 million. The accretive purchase immediately added production, reserves and drilling opportunities on 41,000 gross (22,000 net) acres. Since the acquisition, PetroQuest drilled five wells with a 100% success rate. Our 2004 production from the Carthage Field averaged 5.2 MMcfe per day, yet the Company maintained 28 Bcfe of booked reserves as of year-end 2004. The Company plans to drill 10 to 12 wells in 2005.

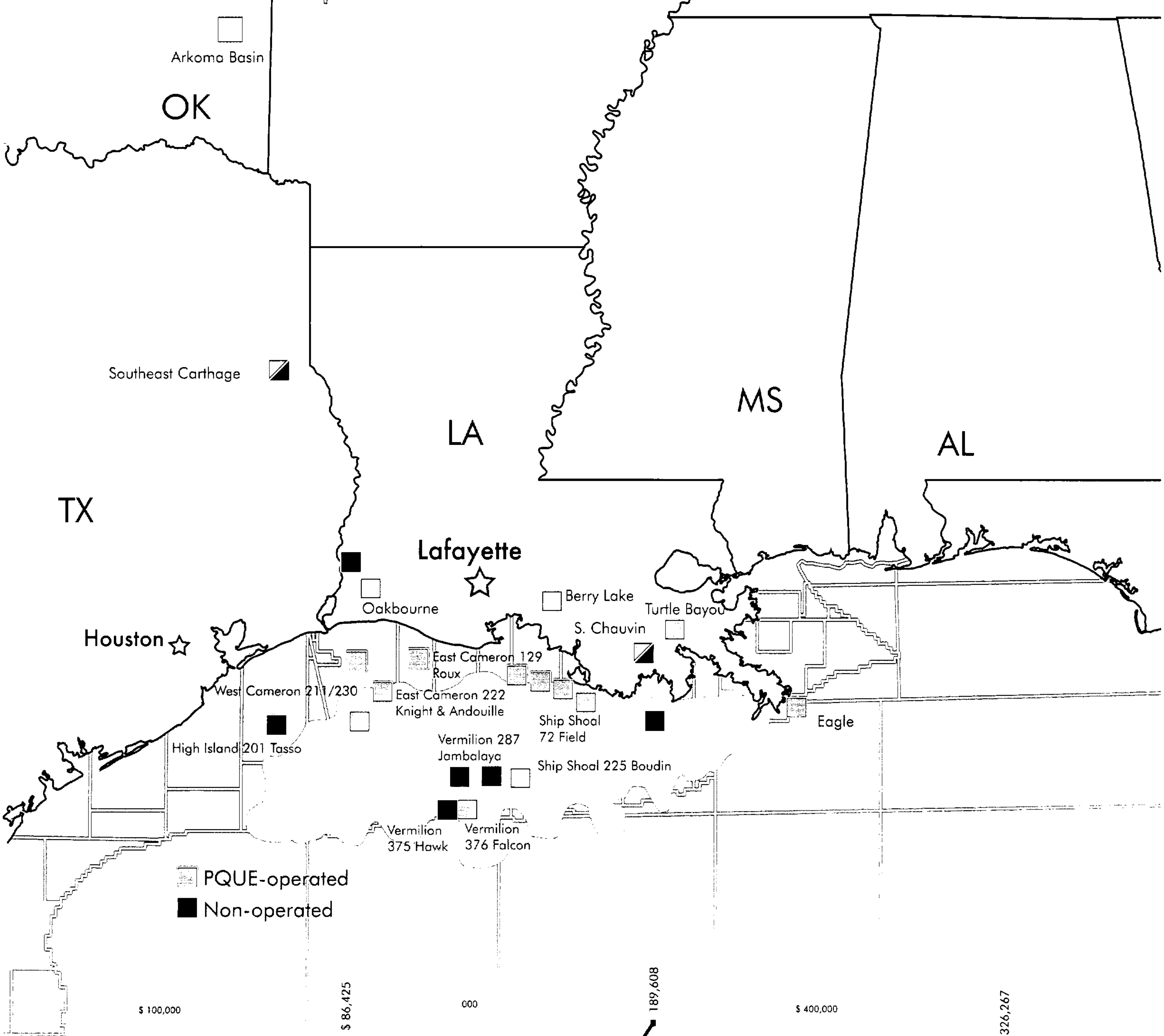
In October 2004, PetroQuest added another long-lived asset purchasing proved, producing reserves, pipelines and hundreds of potential well locations on more than 6,000 net acres in the Arkoma Basin of southeast Oklahoma. This acquisition complemented the 6,000 net acres we assembled earlier in 2004. The $13.5 million acquisition was accretive to earnings and cash flow, and was a catalyst for increasing

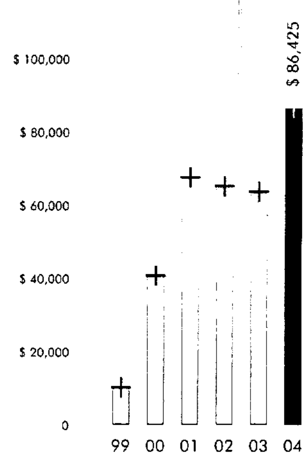
Drilling Horizontal Hartshorne CBM Wells in Oklahoma



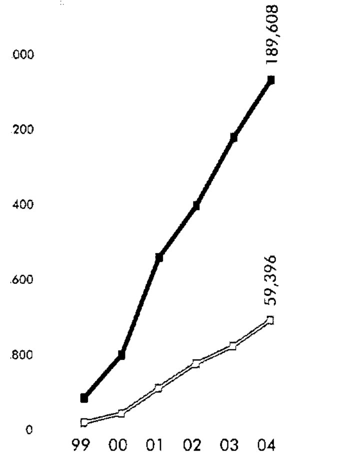
According to the Potential Gas Committee of the Colorado School of Mines, the coalbed gas resource for the Arkoma Basin is estimated to be 1.8 Tcf. The Hartshorne Coal is the preferred target in the Arkoma Basin, both where it occurs as a single seam and where it is split into two. Horizontal wells produce 200% to 300% better than vertical wells. Horizontal wells will ultimately require less capital, and therefore deliver higher returns on invested capital.

Areas of Operation



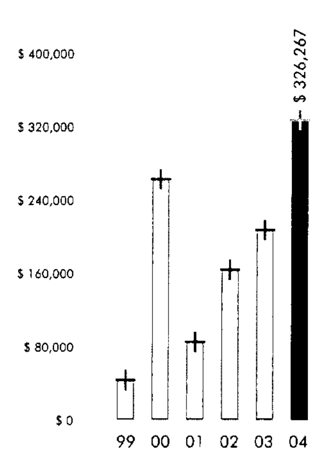


Capital Expenditures
$ in thousands
5-Year CAGR 52%

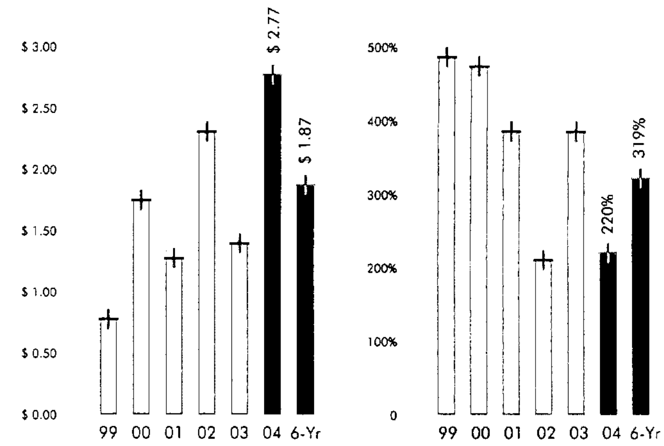


Gross Ultimate Recovery, MMcfe

Cumulative Reserve Additions, MMcfe
Cumulative Production, MMcfe



SEC PV-10, Before Taxes
$ in thousands
5-Year CAGR 50%



F&D Costs, Excluding Revisions
$/Mcfe

Excluding Revisions
Reserve Replacement
Excluding Revisions

the borrowing base under our senior bank facility. In this transaction, we estimate acquiring approximately 8.8 Bcf of proved reserves, 47% proved developed producing and 100% are natural gas. In addition to our proved undeveloped locations, we identified approximately 25 probable and possible reserve locations, including coalbed methane and other prospective horizons, to drill in 2005 and beyond. PetroQuest enjoys an operating base of more than 12,000 net acres and operates 36 miles of pipeline on its Oklahoma property. During 2005, PetroQuest expects to have two rigs working towards the goal of drilling 40 horizontal coalbed methane wells and other horizons.

Approximately 30% of our drilling capital will go to drilling and developing our long-lived resource basins, proving up each location and additional surrounding locations. We will drill approximately 75 wells in 2005, the result of which we expect to be a requisite increase in production. Our activity gives us confidence that in 2005 PetroQuest's production will increase from the Company-record 14.2 Bcfe produced in 2004.

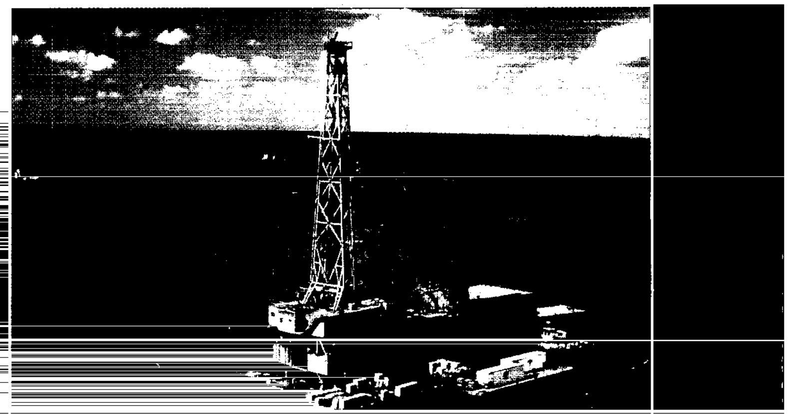
PetroQuest has been active in the Gulf Coast Basin for more than two decades. We control an acreage base which supports our strategy of internally developing exploration and exploitation ideas which offer high rates of return. We have a significant inventory of low, moderate and exploratory projects that we can drill based on our timing and risk appetite. We continue to focus on the Gulf Coast, and we will employ approximately 70% of our 2005 drilling capital in this basin.

Creative Thinking Equals Increased Shareholder Value

Value for PetroQuest's stockholders will be delivered from a combination of drilling and strategic acquisitions. I believe PetroQuest is staffed by an exceptional group of professionals. In my more than 30 years in the oil and gas business, I can undoubtedly say that this is one of the most talented group of individuals that I have ever had the privilege of working with. The Company's management promotes new ideas and empowers people to be creative. PetroQuest's culture is to recognize the work of the staff and the accomplishments of the team's effort. Not surprisingly, the Company's competitive advantage is the people who work as a team to achieve the goal of profitable growth. The goal is pursued throughout the Company and is a source of pride.

As far back as I can remember oil and gas fields have a tendency to get larger, not smaller as technology continues to unlock the mysteries of the subsurface. An excellent example of that is how the East Texas Field developed since oil was first discovered there in the 1930s. I believe PetroQuest operates in some exciting fields that offer excellent opportunities for new well discoveries while increasing the Company's aggregate daily production volumes and proven reserves.

Following time-honored methodologies for computing reserves, we estimate PetroQuest has an inventory of projects totaling approximately 3.5 times the resource base of the 101.4 Bcfe



PetroQuest Energy treads lightly among the South Louisiana marshes. In this gas rich region, PetroQuest will drill approximately ?? wells during 2005.

reported at year-end 2004. Forty-five percent of our reserves at year-end 2004 are located in basins we classify as long-lived. Petro-engineering and geologic studies indicate that long-lived reserves, sometimes referred to as resource plays, typically become larger in size as advanced engineering and completion techniques are applied to increase their productive capacity.

There's a saying in the oil business that truth is found in the drill bit. I believe this same idea has relevant application with the stock market. As I write this letter to you, PetroQuest's stock price is up 47% in 2005. Since our last equity offering on November 4, 2002, the Company's stock price has risen ?2%. Comparatively, the Dow Jones Industrial Average is up ?6%, the Nasdaq Stock Market is up 48% and the Standard & Poor's 500 Index is up 33% since our last equity offering.

By remaining crystal clear on our strategies and goals, we were unobstructed guiding investors in 2004 to the idea that reserves, production and the Company's valuation would be higher in 2004 than in 2003. They were.

I've said before that we have to be smart with our capital as economic reserve growth is most important in our business. We have $38.5 million of outstanding debt at the end of 2004, or 11% based on our total enterprise value. This debt ratio is outstanding; however, as the quality of our asset base continues to improve we may be able to sustain higher levels of debt as we accelerate our production base from our longer-lived asset base.

I am encouraged by the positive fundamentals in our business environment and the macro fundamentals of the energy business. We are tremendously excited about what the future offers us. The entire PetroQuest staff is dedicated to developing new drilling ideas for the single-minded purpose of increasing shareholder value. Our challenge is how we can improve our engineering and financial processes, and geologic thinking. We will remain focused on specific geographic areas that offer multi-year exploitation, development and exploration. The PetroQuest team has the energy to produce the necessary results to grow shareholder value.

Best regards,

Charles T. Goodson

Charles T. Goodson
Chairman and Chief Executive Officer
March 1, 2005

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, 2004

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: 019020

SEC MAIL PROCESSING SECTION
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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: None

Securities registered pursuant to Section 12 (g) of the Act:
Common Stock, Par Value $.001 Per Share
Preferred Stock Purchase Rights
(Title of Class)

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 an accelerated filer (as defined in Rule 12b-2 of the Act).

[X] Yes [ ] No

The aggregate market value of the voting stock held by non-affiliates of the registrant was $155,532,794 as of June 30, 2004 (based on the last reported sale price of such stock on such date on The Nasdaq National Market System).

As of March 1, 2005, the registrant had outstanding 46,211,862 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 12, 2005, which is incorporated by reference into Part III of this Form 10-K.

Table Of Contents

Page No.

PART I

Item 1.	Business	11
Item 2.	Properties	23
Item 3.	Legal Proceedings	24
Item 4.	Submission of Matters to a Vote of Security Holders	24

PART II

Item 5.	Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	25
Item 6.	Selected Financial Data	25
Item 7.	Management's Discussion and Analysis of Financial Condition and Results of Operations	26
Item 7A.	Quantitative and Qualitative Disclosure About Market Risk	32
Item 8.	Financial Statements and Supplementary Data	33
Item 9.	Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	33
Item 9A.	Controls and Procedures	33
Item 9B.	Other Information	35

PART III

Item 10.	Directors and Executive Officers of the Registrant	35
Item 11.	Executive Compensation	35
Item 12.	Security Ownership of Certain Beneficial Owners and Management	35
Item 13.	Certain Relationships and Related Transactions	35
Item 14.	Principal Accounting Fees and Services	35

PART IV

Item 15.	Exhibits and Financial Statement Schedules	35
	Index to Financial Statements	41

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 include, without limitation, statements regarding our estimate of the sufficiency of our existing capital resources and our ability to raise additional capital to fund cash requirements for future operations, and regarding the uncertainties involved in estimating quantities of proved oil and natural gas reserves, in prospect development and property acquisitions and in projecting future rates of production, timing of development expenditures and drilling of wells 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" 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.

PART I

ITEM 1. BUSINESS

Overview and Strategy

PetroQuest Energy, Inc. is an independent oil and gas company incorporated in the State of Delaware with operations in the onshore and offshore regions of the Gulf Coast Basin, as well as in Oklahoma and Texas. Our business strategy is to build shareholder value by increasing proved reserves, production, cash flow and earnings at low finding and development costs through a balanced mix of exploration, development and acquisition activities. During 2004, we increased proved reserves, production, cash flow from operating activities and net income by 22%, 47%, 106% and 349%, respectively, from 2003. To continue to successfully execute our strategy, we plan on:

- *Focusing on the Gulf Coast Basin.* During 2003, we began to diversify a portion of our property base into geographic areas with longer life reserves and production. While diversification is an important factor in balancing risks, we expect to continue to focus the majority of our resources on the Gulf Coast Basin, as we believe this area represents one of the most attractive exploration and development regions in North America. With our large acreage position and extensive 3-D seismic database in the Gulf Coast Basin, we believe our management and technical team's expertise and experience developed over the last 25 years will continue to provide us with attractive reinvestment opportunities.
- *Diversifying our reserve base and technical expertise.* During 2003, we acquired a significant leasehold position in a producing portion of the Southeast Carthage Field in East Texas. During 2004, we expanded our operations to Oklahoma through two transactions. To compliment these transactions, we added personnel with expertise and knowledge specific to these regions dedicated to evaluating and exploiting these properties. These acquisitions strengthen our asset base by adding reserves that have a longer life than our Gulf Coast reserves. During 2004, we drilled 22 wells in Texas and Oklahoma, all of which were productive. At December 31, 2004, approximately 45% of our estimated proved reserves were located outside of the Gulf Coast Basin.
- *Targeting under-exploited fields that have low current production levels.* Using a rigorous prospect selection process that enables us to leverage our experience and knowledge of the Gulf Coast Basin, we target properties with an established production history and existing infrastructure. These fields have often produced from only shallower sands and contain multiple productive horizons that were not targeted during their initial phase of development. By targeting properties with limited current production, our acquisition costs are typically only a small portion of the total capital we will employ over the life of the project.
- *Emphasizing and applying technical expertise.* By applying the latest 3-D and other geoscience technologies to under-exploited properties, we believe we can identify opportunities to significantly increase reserves and production.

- *Operating properties and balancing risk.* By operating the majority of our properties, we can better control the timing and execution of our exploration and development plan. We also balance the risk and reward potential of our prospects by determining our desired working interest and selling the remainder to industry partners on terms where they often agree to pay a disproportionate share of drilling costs relative to their interests. Our management team has developed many successful relationships with major, integrated and large independent producers. We believe these relationships allow us to allocate our capital spending in a way that maximizes return while reducing the inherent risk of exploration activities.
- *Maintaining our financial flexibility.* We seek to maintain unused borrowing capacity under our bank credit facility and sub-debt facility in order to take advantage of future opportunities. We evaluate potential property acquisitions and dispositions, and routinely discuss those opportunities with third parties. While dispositions of producing properties reduce current revenues, sales of properties can provide additional capital for exploration and development of properties that are more important to our long-term growth.

Defined Terms

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 38.

2004 Operational Overview

During 2004, we invested $86.4 million in exploratory, development and acquisition activities as we drilled 18 gross exploratory wells and 15 gross development wells with a 97% drilling success rate. As a result of acquisitions and our drilling success, during 2004 we set records for annual production and year-end proved reserves.

Production during 2004 increased to 14.2 Bcfe, of which 65% was natural gas. Our estimated proved reserves at December 31, 2004 totaled 3,714 MBbl of oil and 79,069 MMcf of natural gas, with 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 $326.3 million. Approximately 68% of our reserves are proved developed reserves and we operate 15 fields representing approximately 65% of the total estimated proved reserves.

Gulf Coast Basin

Ship Shoal 72 Field. During 2004, we invested $13.6 million in this field, including the successful drilling of two exploratory wells. These investments, along with wells completed at the end of 2003, yielded a 16% increase in net field production to 5.7 Bcfe, or 40% of our total 2004 production. Additional developmental opportunities and exploration potential in deeper horizons have been identified and are currently being evaluated for future drilling. In addition, reprocessed 3-D data is currently being reviewed to identify additional opportunities. During 2005, we expect to drill two exploratory wells and perform multiple recompletion operations on the property. We may continue to seek to obtain industry partners in the future development of this property

Main Pass 74 Field. Production commenced from this field in late-December 2003. During the third quarter of 2004, production was shut-in due to third party pipeline damage associated with Hurricane Ivan. We expect production to be restored in March 2005, at which point we will evaluate future plans for the field. Prior to shut-in, this field contributed 1.5 Bcfe to our 2004 production.

East Texas

SE Carthage Field. During December 2003, we acquired working interests in approximately 41,000 acres in this field, which had approximately 80 producing wells. During 2004, we invested $4.2 million on the successful drilling of five development wells. Net production from this field averaged 5.2 MMcfe per day during 2004, or 13% of our total annual average daily production. During 2005, we expect to drill ten wells in this field.

Oklahoma

During 2004, we acquired interests in 12,000 net acres in Oklahoma in two separate transactions. Including acquisition costs, during 2004 we invested $25.6 million and drilled a total of seven exploratory and 10 development wells with a 100% success rate. Net daily production from our Oklahoma fields totaled approximately 2.1 MMcfe during December 2004. We expect to drill over 40 wells during 2005 as we continue to implement our field development plans.

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 gas from our wells depends upon numerous factors beyond our control, including:

- the extent of domestic production and imports of oil and gas;
- the proximity of the gas production to gas pipelines;
- the availability of capacity in such pipelines;
- the demand for oil and 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 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 gas we produce or that favorable prices can be obtained for the oil and gas we produce.

In view of the many uncertainties affecting the supply and demand for oil, gas and refined petroleum products, we are unable to predict future oil and gas prices and demand or the overall effect such prices and demand will have on the Company. For the year ended December 31, 2004, we had two customers who accounted for 26% and 24% of our oil and gas revenue, respectively. For the year ended December 31, 2003, we had three customers who accounted for 27%, 24% and 12% of our oil and gas revenue, respectively. For the year ended December 31, 2002, we had three customers who accounted for 29%, 28% and 10% of our oil and gas revenue, respectively. These percentages do not consider the effects of financial hedges. We do not believe that the loss of any of our oil or 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.

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 tightening of natural gas supply and demand fundamentals has resulted in extremely volatile natural gas prices, which is expected to continue.

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. The FERC indicated in Order No. 561 that it will assess in 2000 how the rate-indexing method is operating. The FERC issued a Notice of Inquiry on July 27, 2000 seeking comment on whether to retain or to change the existing index. After consideration of all the initial and reply comments, the FERC concluded on December 14, 2000 that the PPI-1 index has reasonably approximated the actual cost changes in the oil pipeline industry during the preceding five year period, and that it should be continued for the subsequent five year period.

Federal Leases. We maintain operations located on federal oil and gas leases, which are administered by the Minerals Management Service pursuant to the Outer Continental Shelf Lands Act. These leases are issued through competitive bidding and contain relatively standardized terms. These leases require compliance with detailed Minerals Management Service regulations and orders that are subject to interpretation and change by the Minerals Management Service.

For offshore operations, lessees must obtain Minerals Management Service 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 Environmental Protection Agency, lessees must obtain a permit from the Minerals Management Service prior to the commencement of drilling. The Minerals Management Service has promulgated regulations requiring offshore production facilities located on the Outer Continental Shelf to meet stringent engineering and construction specifications. The Minerals Management Service 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 Minerals Management Service 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 Minerals Management Service 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. Under some circumstances, the Minerals Management Service may require operations on federal leases to be suspended or terminated.

The Minerals Management Service also administers the collection of royalties under the terms of the Outer Continental Shelf Lands Act 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 Minerals Management Service. 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 Minerals Management Service. 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, gathers 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 Minerals Management Service 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. There are legislative proposals pending in the various state legislatures which, 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 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 natural gas facilities, including the operation and construction of pipelines, plants and other facilities for transporting, processing, treating or storing natural gas and other products, are subject to stringent environmental regulation by state and federal authorities including the United States Environmental Protection Agency ("EPA"). Such regulation can increase the cost of planning, designing, installation and operation of such facilities. In most instances, the regulatory requirements relate to water and air pollution control measures. 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 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, that are subject to the Federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. The EPA has limited the disposal options for certain hazardous wastes. Furthermore, it is possible that certain wastes currently exempt from regulation as "hazardous wastes" generated by our oil and gas operations 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 the hazardous substances at a site. CERCLA also authorizes the EPA 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. Neither we nor our predecessors have been designated as a potentially responsible party by the EPA under CERCLA 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 40,000 square feet of leased space, with an exploration office in Houston, Texas, in approximately 5,500 square feet of leased space. We also maintain owned or leased field offices in the areas of the major fields in which we operate properties or have a significant interest. Replacement of any of our leased offices would not result in material expenditures by us as alternative locations to our leased space are anticipated to be readily available

Employees

We had 48 employees as of December 31, 2004. 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 "Investor Relations" section of our Internet 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. Also available on our Internet website is our Business Ethics Policy.

Risk Factors

Risks Related to Our Business, Industry and Strategy

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

As is generally the case in the Gulf Coast Basin where the majority 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. As a result, we must 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.

Oil and natural gas prices are volatile, and a substantial and extended decline in the prices of oil and natural gas would likely have a material adverse effect on us.

Our revenues, 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 are subject to large fluctuations in response to a variety of other factors beyond our control. These factors include:

- relatively minor changes in the supply of and the demand for oil and natural gas;
- market uncertainty;
- the level of consumer product demand;
- weather conditions in the United States;
- the condition of the United States economy;
- 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; and
- the availability of alternate fuel sources.

At various times, excess domestic and imported supplies have depressed oil and natural gas prices. We cannot predict future oil and natural gas prices and prices may decline. Declines in oil and natural gas prices may adversely affect our financial condition, liquidity and results of operations. Lower prices may also reduce the amount of oil and natural gas that we can produce economically and require us to record ceiling test write-downs when prices decline. 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.

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

This document contains estimates of oil and natural gas reserves, and the estimated future net cash flows attributable to those reserves, prepared by Ryder Scott Company, L.P., our independent petroleum and geological engineers. There are 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. 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 a 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 32% of our estimated proved reserves are undeveloped. Estimates of undeveloped 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 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.

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 Securities and Exchange 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 Securities and Exchange Commission to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate 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.

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 "ceiling limit" which is based upon the present value of estimated future net cash flows from proved reserves, discounted at 10%, plus the lower of cost or fair market value of unproved properties. If net capitalized costs of oil and natural gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a "ceiling test write-down." This charge does not impact cash flow from operating activities, but does reduce our stockholders' equity. The risk that we will be required to write down the carrying value of oil and natural gas properties increases when oil and natural gas prices are low or volatile. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves.

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;
- 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 intermediate 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.

Risks Relating to Financing Our Business

We may not be able to obtain adequate financing to execute our operating strategy.

We have historically addressed our long-term liquidity needs through the use of credit facilities, sub-debt facilities, the issuance of equity securities and the use of cash provided by operating activities. We continue to examine the following alternative sources of long-term capital:

- 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 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 and our market value and operating performance. We may be unable to execute our operating strategy if we cannot obtain capital from these sources.

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

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 low 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 complete our drilling program. We may be forced to raise additional debt or equity proceeds to fund such expenditures. We cannot assure you that additional debt or equity financing or cash generated by operations will be available to meet these requirements.

Leverage may materially affect our operations.

We presently have and may incur from time to time debt under our bank credit facility and sub-debt facility. The borrowing base limitation on our bank credit facility is periodically redetermined and upon such redetermination, we could be forced to repay a portion of our bank debt. We may not have sufficient funds to make such repayments.

Our level of debt affects our operations in several important ways, including the following:

- a portion of our cash flow from operations is used to pay interest on borrowings;
- the covenants contained in the agreements governing our debt limit our ability to borrow additional funds or to dispose of assets;
- the covenants contained in the agreements governing our debt may affect our flexibility in planning for, and reacting to, changes in business conditions;
- a high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes;
- our leveraged financial position may make us more vulnerable to economic downturns and may limit our ability to withstand competitive pressures;
- any debt that we incur under our credit facilities will be at variable rates, which could make us vulnerable to increases in interest rates; and
- a high level of debt will affect our flexibility in planning for or reacting to changes in market conditions.

In addition, we may significantly alter our capitalization in order to make future acquisitions or develop our properties. These changes in capitalization may significantly increase our level of debt. A higher level of debt increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of debt depends on our future performance. General economic conditions and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control.

If we are unable to repay our debt at maturity out of cash on hand, we could attempt to refinance such debt, or repay such debt with the proceeds of an equity offering. We cannot assure you that we will be able to generate sufficient cash flow to pay the interest on our debt or that future borrowings or equity financing will be available to pay or refinance such debt. The terms of our bank credit facility and sub-debt facility may also prohibit us from taking such actions. Factors that will affect our ability to raise cash through an offering of our capital stock or a refinancing of our debt include financial market conditions and our market value and operating performance at the time of such offering or other financing. We cannot assure you that any such offering or refinancing can be successfully completed.

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. These financial arrangements take the form of cashless collars or swap contracts and are placed with major trading counter parties we believe represent minimum credit risks. We cannot assure you that these trading counter parties will not become credit risks in the future. Hedging arrangements expose us to risks in some circumstances, including situations when the counter party 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 prices for natural gas and oil. 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.

Risks Relating to Our Ongoing Operations

The loss of key personnel could adversely affect our ability to operate.

Our operations are dependent upon a relatively small group of key management and technical personnel. 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 these individuals could have a detrimental 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.

A material reduction or loss in production from one of our major fields could materially affect our operations.

Production from our Ship Shoal 72 field represented approximately 40% of our total 2004 production. A material reduction or loss of production from this field due to a variety of industry operating hazards as described above could have a material adverse effect on our financial condition and results of operations. During the third quarter of 2004, production from our Main Pass 74 field, which represented approximately 11% of our 2004 production, was shut-in due to third party pipeline damage associated with Hurricane Ivan.

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 maritime employer's liability and comprehensive general liability. Amounts over base coverages are provided by primary and excess umbrella liability policies with maximum limits of $50 million. We also maintain operator's extra expense coverage, which covers the control of drilled 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.

Compliance with environmental and other government regulations is costly and could negatively impact production.

Our operations are subject to numerous 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 recent 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 Common Stock Outstanding

Our management controls a significant percentage of our outstanding common stock and their interests may conflict with those of our stockholders.

Our directors and executive officers and their affiliates beneficially own about 20% of our outstanding common stock at March 1, 2005. This concentration of ownership could have the effect of delaying or preventing a change in control of or otherwise discouraging a potential acquirer from attempting to obtain control of us. This could have a material adverse effect on the market price of our common stock or prevent our stockholders from realizing a premium over the then prevailing market prices for their shares of our 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 be highly volatile. Factors such as announcements concerning changes in prices of oil and natural gas, the success of our exploration and development drilling program, 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.

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 exercise of any outstanding stock awards. 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.

We have reserved approximately 4.3 million shares of common stock for issuance under outstanding options. These shares of common stock are registered for resale on currently effective registration statements. In addition, we have registered the resale of approximately 13.1 million shares of common stock that were issued in private placements to accredited investors in 1999 and 2000, and have granted piggy-back registration rights with respect to 2.25 million shares of common stock underlying a warrant. 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, 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, shareholder rights plan and Delaware law 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 and the provisions of Delaware General Corporation Law 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; and
- a restriction on the ability of stockholders to take actions by written consent.

We are also subject to Section 203 of the Delaware General Corporation Law, which generally prohibits a Delaware corporation from engaging in any of a broad range of business combinations with an interested stockholder for a period of three years following the date on which the stockholder became an interested stockholder.

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.

ITEM 2. PROPERTIES

For a description of the Company's exploration and development activities, see Item 1. Business – 2004 Operational Overview.

Oil and Gas Reserves

The following table sets forth certain information about our estimated proved reserves as of December 31, 2004.

	Proved Developed	Proved Undeveloped	Total Proved
Oil (MBbls)	2,984	730	3,714
Natural Gas and NGL (MMcfe)	50,809	28,260	79,069
Estimated pre-tax future net cash flows	$ 318,132,740	$ 125,353,789	$ 443,486,529
Discounted pre-tax future net cash flows	$ 240,407,688	$ 85,859,717	$ 326,267,405

Ryder Scott Company, L.P., our independent petroleum and geological engineers, prepared the estimates of proved reserves and future net cash flows (and present value thereof) attributable to such proved reserves at December 31, 2004. Reserves were estimated using oil and gas prices and production and development costs in effect at December 31, 2004 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 $43.85 per Bbl of oil and $5.82 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, 2004, in accordance with Statement of Financial 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.

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:

	2004		2003		2002	
	Gross	Net	Gross	Net	Gross	Net
Exploration:						
Productive	17	8.87	4	1.55	2	1.72
Non-productive	1	0.18	2	1.20	1	0.50
Total	18	9.05	6	2.75	3	2.22
Development:						
Productive	15	9.90	4	1.96	5	4.02
Non-productive	-	-	-	-	2	0.77
Total	15	9.90	4	1.96	7	4.79

We owned working interests in 20 gross (7.27 net) producing oil wells and 177 gross (81.72 net) producing gas wells at December 31, 2004. *Three of the 197 gross productive wells at December 31, 2004 had dual completions. At December 31, 2004, we had two wells in progress.*

Leasehold Acreage

The following table shows our approximate developed and undeveloped (gross and net) leasehold acreage as of December 31, 2004:

	Leasehold Acreage			
	Developed		Undeveloped	
	Gross	Net	Gross	Net
Mississippi (onshore)	721	458	88	56
Louisiana (onshore)	3,025	701	6,607	3,171
Louisiana (offshore)	708	477	-	-
Oklahoma (onshore)	18,661	9,196	3,083	3,063
Texas (onshore)	16,373	8,321	26,185	14,090
Federal Waters	45,821	21,346	52,898	36,731
Total	85,309	40,499	88,861	57,111

Leases covering 28% of our gross undeveloped acreage will expire in 2005, 16% in 2006 and 16% in 2007.

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, farm-out 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 2004.

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

Market Price of and Dividends on Common Stock

Our common stock trades on The Nasdaq Stock Market under the symbol "PQUE." The following table lists high and low sales prices per share for the periods indicated:

	NASDAQ Stock Market	
	High	Low
2003		
1st Quarter	$ 4.37	$ 1.48
2nd Quarter	2.79	1.20
3rd Quarter	2.48	1.85
4th Quarter	3.34	2.00
2004		
1st Quarter	$ 3.69	$ 2.52
2nd Quarter	4.36	3.11
3rd Quarter	5.55	4.24
4th Quarter	5.56	4.35

As of March 1, 2005, there were 499 common stockholders of record.

We have not paid dividends on our common stock and intend to retain our cash flow from operations for the future operation and development of our business. In addition, our bank credit facility and sub-debt facility restrict the declaration or payment of any dividends or distributions.

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, 2004 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,				
(in thousands except per share data)	2004	2003 (a)	2002	2001 (b)	2000 (b)
Revenues	$ 84,868	$ 48,688	$ 48,238	$ 55,342	$ 22,561
Net Income	16,348	3,640	2,307	11,645	9,924
Net Income per share:					
Basic	0.37	0.08	0.06	0.37	0.37
Diluted	0.35	0.08	0.06	0.34	0.35
Oil and Gas Properties, net	211,683	160,229	120,746	101,029	56,344
Total Assets	231,617	176,384	132,063	114,639	83,072
Long-term Debt	38,500	22,200	2,400	33,000	6,804
Stockholders' Equity	121,277	107,727	97,770	54,215	41,456

(a) During 2003, the Company adopted SFAS No. 143. The cumulative effect of adoption resulted in a gain of $849,000, or $0.02 per share.

(b) The Company's financial statements for 2001 and 2000 were audited by Arthur Andersen LLP, which has ceased operations.

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 with operations in the onshore and offshore regions of the Gulf Coast Basin, as well as in portions of Oklahoma and East Texas. Our business strategy is to build shareholder value by increasing proved reserves, production, cash flow from operations and net income at low finding and development costs. During 2004, we successfully executed this strategy as we increased these metrics 22%, 47%, 106% and 349%, respectively, from 2003.

The record 2004 increases were the result of our ability to capitalize on another year of strong commodity prices which enabled us to substantially increase our capital expenditures. During 2004, we invested $86.4 million, a 36% increase from 2003, into our exploration, development and acquisition activities. These investments yielded a 97% success rate on 33 wells drilled and the consummation of several strategic acquisitions.

During 2003, we began to diversify a portion of our property base into geographic areas with longer life reserves and production. We acquired a significant leasehold position in a producing portion of the Southeast Carthage field in East Texas during December 2003 and we expanded our operations to Oklahoma through two acquisitions during 2004. To compliment these transactions, we added personnel with expertise and knowledge specific to these regions dedicated to evaluating and exploiting these properties. During 2004, we drilled 22 wells in Texas and Oklahoma, all of which were productive. At December 31, 2004, approximately 45% of our estimated proved reserves were located outside of the Gulf Coast Basin.

While diversification is an important factor in balancing risks, we expect to continue to focus the majority of our resources on the Gulf Coast Basin, as we believe this area represents one of the most attractive exploration and development regions in North America. With our large acreage position and extensive 3-D seismic database in the Gulf Coast Basin, we believe our management and technical team's expertise and experience developed over the last 25 years will continue to provide us with attractive reinvestment opportunities.

Critical Accounting Policies

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 and dismantlement, restoration and abandonment costs, net of estimated salvage values. 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, 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. Declines in prices or reserves could result in a future write-down of oil and gas properties.

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

Future Abandonment Costs

Future abandonment costs include costs to dismantle and relocate or dispose of our production platforms, gathering systems, wells and related structures and restoration costs of land and seabed. We develop estimates of these costs for each of our properties based upon the type of production structure, depth of water, reservoir characteristics, depth of the reservoir, market demand for equipment, currently available procedures and consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. The accounting for future abandonment costs changed on January 1, 2003, with the adoption of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations." See New Accounting Standards in the Notes to Consolidated Financial Statements for a further discussion of this accounting standard.

Reserve Estimates

Our estimates of oil and gas reserves are, by necessity, 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 the extent that 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

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 equity through other comprehensive income, net of related taxes, to the extent the hedge is effective. The cash settlements of cash flow hedges are recorded into revenue. Instruments not qualifying for hedge accounting treatment are recorded in the balance sheet and changes in fair value are recognized in earnings as derivative expense (income).

Our hedges are specifically referenced to the NYMEX index prices we receive for our Gulf Coast Basin production. As a result, there is a high correlation between fluctuations in the price we receive for our Gulf Coast Basin oil and gas and the indexed price of the settlement of our hedges. At December 31, 2004, our hedging contracts were considered effective cash flow hedges.

Estimating the fair values of hedging derivatives requires complex calculations incorporating estimates of future prices, discount rates and price movements. Therefore, we choose to obtain the fair value of our commodity derivatives from the counter parties to those contracts. Since the counter parties are market makers, they are able to provide us with a literal market value, or what they would be willing to settle such contracts for as of the given date.

New Accounting Standards

On December 16, 2004, the Financial Accounting Standards Board 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." Generally, the approach in SFAS 123(R) is similar to the approach in SFAS 123. However, SFAS 123(R) requires all share based payments to employees, including grants of employee stock options, to be recognized in the income statement based on their estimated fair values. Pro forma disclosure is no longer an alternative. SFAS 123(R) requires adoption in the first interim or annual period beginning after June 15, 2005. We expect to adopt the standard July 1, 2005.

SFAS 123(R) permits adoption using one of two methods. A "modified prospective" method in which compensation cost is recognized beginning with the effective date 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. An alternate method, the "modified retrospective" method includes the requirements of the modified prospective method described above, but also permits entities to restate based on the amounts previously recognized under SFAS 123 for purposes of pro forma disclosures (see Note 1 in the Notes to the Consolidated Financial Statements) either (a) all prior periods presented or (b) prior interim periods of the year of adoption.

We currently account for our stock-based compensation plans under the principles prescribed by APB Opinion No. 25. Accordingly, no stock option compensation cost is reflected in net income, as all options granted under the plan had an exercise price equal to the market value of the underlying common stock on the date of grant. Accordingly, the adoption of SFAS 123(R) will have a significant impact on our results of operations, but will have no impact on our overall financial position.

The specific impact of the adoption cannot be predicted at this time because it will depend on the level of share-based payments granted in the future. However, had we adopted SFAS 123(R) in prior periods, the impact would approximate the impact of SFAS 123 as described in Note 1 in the Notes to the Consolidated Financial Statements. SFAS 123(R) also requires the benefits of tax deductions in excess of recognized compensation cost to be reflected as a financing cash flow, rather than as an operating cash flow as currently required. We did not recognize any excess tax deductions during 2004, 2003 or 2002 in connection with the exercise of stock options.

In September 2004, the Securities and Exchange Commission adopted 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. We expect to begin applying SAB No. 106 in the first quarter of 2005.

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, 2004, 2003 and 2002:

	Year Ended December 31, 2004	2003	2002
Production:			
Oil (Bbls)	818,405	744,575	929,181
Gas (Mcf)	9,305,075	5,192,760	7,765,142
Total Production (Mcfe)	14,215,505	9,660,210	13,340,228
Sales:			
Total oil sales	$ 28,896,550	$ 21,196,246	$ 23,294,514
Total gas sales	55,698,797	26,713,611	24,846,723
Total oil and gas sales	$ 84,595,347	$ 47,909,857	$ 48,141,237
Average sales prices:			
Oil (per Bbl)	$ 35.31	$ 28.47	$ 25.07
Gas (per Mcf)	5.99	5.14	3.20
Per Mcfe	5.95	4.96	3.61

The above sales and average sales prices include reductions to revenue related to the settlement of gas hedges of ($1,064,000), ($2,540,000) and ($733,000) and oil hedges of ($4,197,000), ($1,923,000) and ($128,000) for the years ended December 31, 2004, 2003 and 2002, respectively.

Comparison of Results of Operations for the Years Ended December 31, 2004 and 2003

Net income for the year ended December 31, 2004 increased 349% to $16,348,000 as compared to $3,640,000 for the year ended December 31, 2003. The results were attributable to the following components:

Production

Oil production in 2004 totaled 818,405 barrels, a 10% increase from the year ended December 31, 2003. Natural gas production in 2004 increased 79% to 9.3 Bcf from 2003 gas production of 5.2 Bcf. On a gas equivalent basis, production for 2004 totaled 14.2 Bcfe, a 47% increase from the 2003 period. The increase in production as compared to 2003 was the result of our current year drilling success, which included only one dry hole out of 33 wells drilled, and our acquisition of primarily gas producing properties in the Southeast Carthage field in December 2003, which contributed 1.9 Bcfe, or 13%, to our net 2004 production.

Prices

Average oil prices per barrel during 2004 were $35.31 versus $28.47 during 2003. Average gas prices per Mcf were $5.99 during 2004 as compared to $5.14 during 2003. Stated on a gas equivalent basis, unit prices received during 2004 were 20% higher than the prices received during 2003.

Revenue

Oil and gas sales during 2004 increased 77% to $84,595,000 from $47,910,000 during 2003 as a result of higher production volumes and commodity prices.

During 2004, interest and other income decreased to $273,000 from $778,000 during 2003. Interest and other income recognized during 2003 included the settlement of a lawsuit.

Expenses

As a result of the increase in the number of wells we participate in, lease operating expenses for 2004 increased to $13,161,000 from $9,449,000 during 2003. However, on an Mcfe basis, lease operating expenses decreased 5% from $0.98 per Mcfe in 2003 to $0.93 per Mcfe in 2004.

Production taxes increased to $1,549,000 during 2004 from $884,000 during 2003. The increase is due to higher onshore production as a result of acquisitions in Texas and Oklahoma, as well as an increase in the Louisiana severance tax rate effective July 1, 2004.

General and administrative expenses during 2004 totaled $6,212,000 as compared to $4,444,000 during 2003, net of amounts capitalized of $4,036,000 and $3,611,000, respectively. The increases in general and administrative expenses are primarily due to higher accrued bonuses in 2004 resulting from the Company's improved performance in 2004 relative to 2003.

Depreciation, depletion and amortization ("DD&A") expense on oil and gas properties for 2004 increased 31% to $34,971,000 as compared to $26,654,000 in 2003. On an Mcfe basis, however, the DD&A rate on oil and gas properties totaled $2.46 per Mcfe during 2004 as compared to $2.76 per Mcfe for 2003. The decrease in 2004 per unit DD&A was due primarily to acquisitions made during late 2003 and throughout 2004 at a lower per unit cost than our historical depletion rate and our 2004 drilling success.

Interest expense, net of amounts capitalized on unevaluated prospects, totaled $2,817,000 during 2004 versus $579,000 during 2003. The increase in interest costs is the result of borrowings made in December 2003 to fund the acquisition of properties in the Carthage field and borrowings made in October 2004 to fund the acquisition of properties in Oklahoma. We capitalized $883,000 and $451,000 of interest during 2004 and 2003, respectively.

Derivative expense totaled $2,000 and $1,071,000 during 2004 and 2003, respectively. The expense recorded in 2003 was the result of a gas derivative instrument and an interest rate swap that did not qualify for hedge accounting treatment. These instruments expired during December 2003 and November 2004, respectively.

Income tax expense of $8,511,000 was recognized during 2004 as compared to $1,690,000 being recorded during 2003. The increase is due to an increase in operating profit during the current year. We provide for income taxes at a statutory rate of 35% adjusted for permanent differences expected to be realized, primarily statutory depletion.

Comparison of Results of Operations for the Years Ended December 31, 2003 and 2002

Net income totaled $3,640,000 and $2,307,000 for the years ended December 31, 2003 and 2002, respectively. The results are attributable to the following components:

Production

Oil production in 2003 decreased 20% from the year ended December 31, 2002. Natural gas production in 2003 decreased 33% from the year ended December 31, 2002. On an Mcfe basis, total production for the year ended December 31, 2003 decreased 28% over the same period in 2002. The decrease in 2003 total production volumes, as compared to 2002, was due to the consistent decline of our Gulf Coast production and well performance at our Bordeaux and Berry Lake wells, partially offset by the drilling success during the second half of 2003.

Prices

Average oil prices per barrel during 2003 were $28.47 as compared to $25.07 for the same period in 2002. Average gas prices per Mcf were $5.14 during 2003 as compared to $3.20 for the same period in 2002. Stated on an Mcfe basis, unit prices received during 2003 were 37% higher than the prices received during 2002.

Revenue

Oil and gas sales during 2003 decreased to $47,910,000 as compared to 2002 revenues of $48,141,000. The decrease in production volumes partially offset by the significant increase in realized commodity prices resulted in the decrease in revenue.

Interest and other income during 2003 increased to $778,000 as compared to $97,000 during 2002. The increase is primarily the result of the settlement of a lawsuit during 2003 and the related accounting entries as a result of the settlement.

Expenses

Lease operating expenses for 2003 decreased to $9,449,000 from $9,988,000 during 2002. On an Mcfe basis, lease operating expenses increased from $0.75 per Mcfe in 2002 to $0.98 in 2003. The increase during 2003 on an Mcfe basis is primarily due to an overall decline in production rates and the repairs and maintenance costs at the Ship Shoal 72 field, which did not increase production rates.

General and administrative expenses during 2003 totaled $4,444,000 as compared to expenses of $5,009,000 during 2002, net of amounts capitalized of $3,611,000 and $3,664,000, respectively. The decreases in general and administrative expenses are primarily due to a decrease in staffing levels during 2003. We recognized $381,000 and $345,000 of non-cash compensation expense during 2003 and 2002, respectively.

Depreciation, depletion and amortization ("DD&A") expense on oil and gas properties for 2003 decreased 4% to $26,654,000 as compared to $27,751,000 in 2002. On an Mcfe basis, which reflects the changes in production, the DD&A rate on oil and gas properties for 2003 was $2.76 per Mcfe as compared to $2.08 per Mcfe for 2002. The increase in 2003 per unit DD&A as compared to 2002 is due primarily to costs in excess of previous estimates during the previous twelve months and unsuccessful exploration drilling results during 2002 and 2003.

Interest expense, net of amounts capitalized on unevaluated prospects, increased $301,000 during 2003 as compared to 2002. The increase is the result of an increase in the average debt levels during 2003, the higher interest rates on our sub-debt facility and the previously capitalized costs that were expensed on our prior credit facility. We capitalized $451,000 and $619,000 of interest during 2003 and 2002, respectively.

Derivative expense increased $513,000 during 2003 as compared to 2002. This increase is primarily the result of one of our gas derivatives being recorded on the income statement because of a decline in production in the specific field to which the derivative was designated. The monthly settlements related to this derivative have been recorded to derivative expense effective during June 2003.

Income tax expense of $1,690,000 was recognized during 2003 as compared to $1,288,000 being recorded during 2002. The increase is due to an increase in operating profit during the current year. We provide for income taxes at a statutory rate of 35% adjusted for permanent differences expected to be realized, primarily statutory depletion.

Liquidity and Capital Resources

We have financed our exploration and development activities to date principally through cash flow from operations, bank borrowings, private and public offerings of common stock and sales of properties.

Source of Capital: Operations

Net cash flow from operating activities increased from $34,190,000 during 2003 to $70,310,000 during 2004. This increase resulted from higher production and realized commodity prices during the current year. Our working capital deficit at December 31, 2004 totaled ($24,429,000) versus a deficit of ($15,299,000) at December 31, 2003. The increased working capital deficit is the result of increased expenditures during 2004 and the corresponding timing of accounts payable related to exploration, development and operating costs, as well as the increase in our hedging liability, which is the result of the increase in estimated future commodity prices. We believe that our working capital balance should be viewed in conjunction with availability of borrowings under our bank credit facilities when measuring liquidity. At December 31, 2004, our borrowing availability totaled $24,500,000.

Source of Capital: Debt

We entered into a bank credit facility on May 14, 2003. Pursuant to the credit agreement, PetroQuest and our subsidiary PetroQuest Energy, L.L.C. (the "Borrower") have a $75 million revolving credit facility that permits us to borrow amounts from time to time based on the available borrowing base as determined in the bank credit facility. The bank credit facility is secured by a mortgage on substantially all of the Borrower's oil and gas properties, a pledge of the membership interest of the Borrower and PetroQuest's corporate guarantee of the indebtedness of the Borrower. The borrowing base under the bank credit facility is based upon the valuation as of April 1 and October 1 of each year of the Borrower's mortgaged properties, projected oil and gas prices, and any other factors deemed relevant by the lenders. We, or the lenders, may request additional borrowing base re-determinations. As of December 31, 2004, the borrowing base under the bank credit facility was $43 million and was subject to monthly reductions of $1.5 million beginning February 2005. The lenders will determine future monthly reductions in connection with each borrowing base re-determination.

At December 31, 2004, we had $26.5 million of borrowings and no letters of credit issued pursuant to the bank credit facility.

Outstanding balances on the revolving credit facility bear interest at either the bank's prime rate plus a margin (based on a sliding scale of 0.75% to 1.25% based on borrowing base usage but never less than the Federal Funds Effective Rate plus 0.5%) or the Eurodollar rate plus a margin (based on a sliding scale of 2.0% to 2.5% depending on borrowing base usage). The bank credit facility also allows us to use up to $5 million of the borrowing base for letters of credit for fees equal to the applicable margin rate for Eurodollar advances.

We are subject to certain restrictive financial and non-financial covenants under the bank credit facility including a minimum current ratio of 1.0 to 1.0, as defined in the credit facility agreement. The bank credit facility also requires the Borrower to establish and maintain commodity hedges covering at least 50% of its proved developed producing reserves on a rolling twelve-month basis. As of December 31, 2004, we were in compliance with all of the covenants in the bank credit facility. The bank credit facility matures on May 14, 2006.

On November 6, 2003, we obtained a $20 million subordinated term credit facility from Macquarie Americas Corp. The sub-debt facility carries an interest rate of prime plus 5.5%, is secured by a second mortgage on substantially all of our oil and gas properties and matures November 30, 2006. The sub-debt facility is available for advances at any time until December 31, 2005, subject to the restrictive covenants of the sub-debt facility and Macquarie approval. At closing, Macquarie received warrants to purchase 1,250,000 shares of our common stock at an exercise price of $2.30 per share.

In conjunction with the December 2003 property acquisition, the sub-debt facility was amended, the original warrants were cancelled and 2,250,000 warrants were issued to Macquarie. During January 2004, the sub-debt facility, including the note, liens, warrants and all other rights of Macquarie thereunder, was assigned to Macquarie Bank Limited, an affiliate of Macquarie Americas Corp. During February 2005, Macquarie exercised the outstanding warrants utilizing a cashless exercise provision resulting in the issuance of 1,506,466 shares.

As of December 31, 2004, we had $12 million borrowed under the sub-debt facility, which was primarily used to fund our acquisition of properties in the Southeast Carthage field. The sub-debt facility contains certain restrictive financial and non-financial covenants, including a minimum current ratio of 1.0 to 1.0, a total debt threshold of $60 million and a cumulative minimum production and net operating cash flow threshold, all as defined in the sub-debt facility. The sub-debt facility also requires us to establish and maintain commodity hedges covering at least 65% of our proved developed producing reserves through November 2006. As of December 31, 2004, we were in compliance with all of the covenants in the sub-debt facility.

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. Although we do not anticipate debt covenant violations, our ability to comply with 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: Issuance of Securities

We have 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 from time to time or when financing needs arise. The registration statement does not provide assurance that we will or could sell any such securities.

Use of Capital: Exploration and Development

We have an exploration and development program budget for 2005 that will require significant capital. Our capital budget for 2005 is approximately $80 million of which approximately 70% will be allocated to the Gulf Coast Basin. Based on our outlook of commodity prices and estimated production, we believe that cash flows from operations and available borrowing capacity under our credit facilities will be sufficient to fund planned 2005 exploration and development activities. In the future, our exploration and development activities could require additional financings, which may include sales of additional equity or debt securities, additional borrowings from banks or other lenders, sales of properties, or joint venture arrangements with industry partners. 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 delay 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, 2004 (in thousands):

	Total	2005	2006	2007	2008	2009	After 2009
Bank debt	$ 26,500	$ -	$ 26,500	$ -	$ -	$ -	$ -
Subordinated debt	12,000	-	12,000	-	-	-	-
Operating leases (1)	4,489	832	772	742	741	755	647
Capital projects (2)	16,393	1,155	1,506	913	638	1,933	10,248

(1) Consists primarily of leases for office space and leases for equipment rentals.
(2) Consists of estimated future obligations to abandon our leased properties.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISKS

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 2005, a 10% decline in the estimated average 2005 prices we receive for our crude oil and natural gas production would have an approximate $11 million impact on our revenues.

In a typical hedge transaction, we will have the right to receive from the counterparts 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 counterparts this difference multiplied by the quantity hedged.

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.

As of December 31, 2004, we had entered into the following oil and gas contracts accounted for as cash flow hedges:

Production Period	Instrument Type	Daily Volumes	Weighted Average Price
Natural Gas:			
2005	Swap	750 MMBtu	$4.55
First Quarter 2005	Costless Collar	11,000 MMBtu	$4.50 - 7.99
Second Quarter 2005	Costless Collar	8,000 MMBtu	$4.50 - 6.67
Third Quarter 2005	Costless Collar	5,500 MMBtu	$4.50 - 7.28
Fourth Quarter 2005	Costless Collar	4,500 MMBtu	$4.50 - 7.40
2006	Swap	1,500 MMBtu	$4.53
January - June 2006	Costless Collar	2,500 MMBtu	$4.50 - 9.27
Crude Oil:			
First Quarter 2005	Costless Collar	1,000 Bbls	$26.50 - 42.85
Second Quarter 2005	Costless Collar	750 Bbls	$25.33 - 35.03
July - December 2005	Costless Collar	500 Bbls	$23.00 - 26.20
2006	Costless Collar	200 Bbls	$23.00 - 26.40

At December 31, 2004, we recognized a liability of $6.5 million related to the estimated fair value of these derivative instruments.

We also evaluated the potential effect that near term changes may have on our credit facilities. Debt outstanding under the credit facilities is subject to a floating interest rate and represents 100% of our debt as of December 31, 2004. Based upon an analysis utilizing the actual interest rate in effect and balances outstanding as of December 31, 2004 and assuming a 10% increase in interest rates and no changes in the amount of debt outstanding, the potential effect on interest expense for 2005 is approximately $300,000.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Information concerning this Item begins on page 41.

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, we carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the disclosure controls and procedures pursuant to Rule 13a-15 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective, in all material respects, with respect to the recording, processing, summarizing and reporting, within the time periods specified in the Securities and Exchange Commission's rules and forms, of information required to be disclosed by us in the reports that we file or submit under the Exchange Act. There have been no significant changes in our internal control over financial reporting during the period covered by this report that have materially affected, or are reasonably likely to materially affect, our 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, 2004. 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, 2004 based upon criteria in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on our assessment, management believes that our internal control over financial reporting was effective as of December 31, 2004 based on these criteria.

Our management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2004 has been audited by Ernst & Young LLP, our independent registered public accounting firm, as stated in their report below.

March 2, 2005

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

/s/ Michael O. Aldridge
Michael O. Aldridge
Senior Vice President and Chief Financial Officer

Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting

The Board of Directors and Shareholders
PetroQuest Energy, Inc.

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that PetroQuest Energy, Inc. maintained effective internal control over financial reporting as of December 31, 2004, 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. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of 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, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, 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, management's assessment that PetroQuest Energy, Inc. maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, PetroQuest Energy, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, 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, 2004 and 2003, and the related consolidated statements of income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2004 of PetroQuest Energy, Inc. and our report dated March 2, 2005 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
New Orleans, Louisiana
March 2, 2005

ITEM 9B. OTHER INFORMATION

Ralph J. Daigle, our vice-chairman of the board, has notified us of his intention to retire from all positions effective March 31, 2005.

PART III

ITEMS 10, 11, 12, 13 & 14

For information concerning Item 10. Directors and Executive Officers of the Registrant, Item 11. Executive Compensation, Item 12. Security Ownership of Certain Beneficial Owners and Management, Item 13. Certain Relationships and Related Transactions and Item 14. Principal Accounting Fees and Services, see the definitive Proxy Statement of PetroQuest Energy, Inc. relating to the Annual Meeting of Stockholders to be held May 12, 2005, which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

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 41 through 57 of this Form 10-K:

Report of Independent Registered Public Accounting Firm
Consolidated Balance Sheets as of December 31, 2004 and 2003
Consolidated Statements of Income for the three years ended December 31, 2004
Consolidated Statements of Stockholder's Equity for the three years ended December 31, 2004
Consolidated Statements of Cash Flows for the three years ended December 31, 2004
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 the Company (incorporated herein by reference to Exhibit 4.1 to Form 8-K dated September 16, 1998)

3.2 Bylaws of the Company (incorporated herein by reference to Exhibit 4.2 to Form 8-K dated September 16, 1998).

3.3 Certificate of Domestication of Optima Petroleum Corporation (incorporated herein by reference to Exhibit 4.4 to Form 8-K dated 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).

4.1 Warrant to Purchase Common Shares of PetroQuest Energy, Inc. (incorporated by reference to Exhibit 4.1 to Form 8-K filed December 29, 2003).

4.2 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).

4.3 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).

†10.1 PetroQuest Energy, Inc. 1998 Incentive Plan, as amended and restated effective December 1, 2000 (incorporated herein by reference to Appendix A to Proxy Statement on Schedule 14A filed April 20, 2001).

10.2 Amended and Restated Credit Agreement, dated as of May 14, 2003, by and between PetroQuest Energy, LLC, PetroQuest Energy, Inc., Bank One, NA, Banc One Capital Markets, Inc., and certain other Lenders (incorporated herein by reference to Exhibit 10.1 to Form 10-Q filed August 13, 2003).

10.3 Guaranty dated May 14, 2003, between PetroQuest Energy, Inc. and Bank One, NA, as Agent for the Lenders (incorporated herein by reference to Exhibit 10.2 to Form 10-Q filed August 13, 2003).

10.4 First Amendment to Amended and Restated Credit Agreement dated as of November 6, 2003, by and among PetroQuest Energy, L.L.C., PetroQuest Energy, Inc.; Bank One, N.A., and Union Bank of California, N.A. (incorporated herein by reference to Exhibit 10.4 to Form 10-Q filed November 13, 2003).

10.5 Second Amendment to Amended and Restated Credit Agreement dated as of December 23, 2003, by and among PetroQuest Energy, L.L.C., PetroQuest Energy, Inc., and Bank One, N.A. (incorporated herein by reference to Exhibit 10.2 to Form 8-K filed December 29, 2003).

10.6 Third Amendment to Amended and Restated Credit Agreement dated as of July 27, 2004, by and among PetroQuest Energy, L.L.C., PetroQuest Energy, Inc., and Bank One, N.A. (incorporated herein by reference to Exhibit 10.1 to Form 10-Q filed July 30, 2004).

10.7 Fourth Amendment to Amended and Restated Credit Agreement dated as of October 14, 2004 by and between PetroQuest Energy, LLC, PetroQuest Energy, Inc. and Bank One, N.A. (incorporated by reference to Exhibit 10.1 on Form 8-K filed October 19, 2004).

10.8 Fifth Amendment to Amended and Restated Credit Agreement entered into as of November 3, 2004 by and between PetroQuest Energy, LLC, PetroQuest Energy, Inc., Pittrans Inc. (a wholly owned subsidiary of PetroQuest Energy, LLC) and Bank One, N.A. (incorporated by reference to Exhibit 10.1 on Form 8-K filed November 15, 2004).

10.9 Senior Second Lien Secured Credit Agreement dated November 6, 2003, between PetroQuest Energy, L.L.C., PetroQuest Energy, Inc., each of the Lenders from time to time party thereto; and Macquarie Americas Corp., as administrative agent for the Lenders (incorporated herein by reference to Exhibit 10.1 to Form 10-Q filed November 13, 2003).

10.10 Unconditional Guaranty Agreement dated November 6, 2003, by PetroQuest Energy, Inc. to Macquarie Americas Corp., as administrative agent for the benefit of the Lenders under the Credit Agreement (incorporated herein by reference to Exhibit 10.2 to Form 10-Q filed November 13, 2003).

10.11 First Amendment to Second Lien Secured Credit Agreement dated December 23, 2003, among PetroQuest Energy, L.L.C., PetroQuest Energy, Inc., each of the Lenders from time to time party thereto, and Macquarie Americas Corp., as administrative agent for the Lenders (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed December 29, 2003).

10.12 Second Amendment to Second Lien Secured Credit Agreement dated July 27, 2004, among PetroQuest Energy, L.L.C., PetroQuest Energy, Inc., each of the Lenders from time to time party thereto, and Macquarie Americas Corp., as administrative agent for the Lenders (incorporated herein by reference to Exhibit 10.2 to Form 10-Q filed July 30, 2004).

10.13 Third Amendment to Second Lien Secured Credit Agreement dated as of October 14, 2004 by and between PetroQuest Energy, LLC, PetroQuest Energy, Inc. and Macquarie Bank Limited (incorporated by reference to Exhibit 10.2 on Form 8-K filed October 19, 2004).

10.14 Fourth Amendment to Second Lien Secured Credit Agreement dated as of December 29, 2004 by and between PetroQuest Energy, LLC and Macquarie Bank Limited (incorporated by reference to Exhibit 10.1 on Form 8-K filed December 30, 2004).

†10.15 Employment Agreement dated September 1, 1998, between PetroQuest Energy, Inc. and Charles T. Goodson (incorporated herein by reference to Exhibit 10.2 to Form 8-K dated September 16, 1998).

†10.16 Employment Agreement dated September 1, 1998, between PetroQuest Energy, Inc. and Ralph J. Daigle (incorporated herein by reference to Exhibit 10.4 to Form 8-K dated September 16, 1998).

†10.17 First Amendment to Employment agreement dated September 1, 1998 between PetroQuest Energy, Inc. and Charles T. Goodson dated July 30, 1999 (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated August 9, 1999)

†10.18 First Amendment to Employment Agreement dated September 1, 1998 between PetroQuest Energy, Inc. and Ralph J. Daigle dated July 30, 1999 (incorporated herein by reference to Exhibit 10.3 to Form 8-K dated August 9, 1999).

†10.19 Employment Agreement dated May 8, 2000 between PetroQuest Energy, Inc. and Michael O. Aldridge (incorporated by reference to Exhibit 10.1 to the Form 10-Q filed August 14, 2000).

†10.20 Employment Agreement dated December 15, 2000 between PetroQuest Energy, Inc. and Arthur M. Mixon, III. (incorporated herein by reference to Exhibit 10.12 to Form 10-K filed March 30, 2001).

†10.21 Employment Agreement dated April 20, 2001 between PetroQuest Energy, Inc. and Daniel G. Fournerat (incorporated herein by reference to Exhibit 10.1 to Form 10-Q filed May 15, 2001).

†10.22 Employment Agreement dated April 20, 2001 between PetroQuest Energy, Inc. and Dalton F. Smith III (incorporated herein by reference to Exhibit 10.21 to Form 10-K filed March 13, 2002).

†10.23 Employment agreement dated July 28, 2003, between PetroQuest Energy, Inc. and Stephen H. Green (incorporated herein by reference to Exhibit 10.3 to Form 10-Q filed November 13, 2003).

†10.24 Form of Termination Agreement Between PetroQuest Energy, Inc. and each of its executive officers, including Charles T. Goodson, Ralph J. Daigle, Michael O. Aldridge, Arthur M. Mixon, III, Daniel G. Fournerat, Dalton F. Smith III and Stephen H. Green (incorporated herein by reference to Exhibit 10.20 to Form 10-K filed March 13, 2002).

†10.25 Form of Indemnification Agreement between PetroQuest Energy, Inc. and each of its directors and executive officers, including Charles T. Goodson, Ralph J. Daigle, Daniel G. Fournerat, E. Wayne Nordberg, William W. Rucks, IV, Michael O. Aldridge, Arthur M. Mixon, III, Dalton F. Smith III, Michael L. Finch, W.J. Gordon, III and Stephen H. Green (incorporated herein by reference to Exhibit 10.21 to Form 10-K filed March 13, 2002).

14.1 Business Ethics Policy (incorporated by reference to Exhibit 14.1 to Form 10-K filed March 12, 2004).

*21.1 Subsidiaries of the Company.

*23.1 Consent of Independent Registered Public Accounting Firm.

*23.2 Consent of Ryder Scott Company, L.P.

*31.1 Certification of Chief Executive Officer pursuant to Rule 13-a-14(a) / Rule 15d-14(a), promulgated under the Securities Exchange Act of 1934, as amended.

*31.2 Certification of Chief Financial Officer pursuant to Rule 13-a-14(a) / Rule 15d-14(a), promulgated under the Securities Exchange Act of 1934, as amended.

*32.1 Certification pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, of Chief Executive Officer.

*32.2 Certification pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, of Chief Financial Officer.

(b) Exhibits. See Item 15 (a) (3) above.
(c) Financial Statement Schedules. None

* Filed herewith.
† Management contract or compensatory plan or arrangement

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 ornatural 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 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.

MMBbls. 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. 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 March 3, 2005.

PETROQUEST ENERGY, INC.

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

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 3, 2005.

By: /s/ Charles T. Goodson
CHARLES T. GOODSON
Chairman of the Board, Chief Executive Officer and Director (Principal Executive Officer)

By: /s/ Ralph J. Daigle
RALPH J. DAIGLE
Vice Chairman of the Board

By: /s/ Michael O. Aldridge
MICHAEL O. ALDRIDGE
Senior Vice President, Chief Financial Officer, Treasurer and Director (Principal Financial and Accounting Officer)

By: /s/ W.J. Gordon, III
W.J. GORDON, III
Director

By: /s/ Michael L. Finch
MICHAEL L. FINCH
Director

By: /s/ E. Wayne Nordberg
E. WAYNE NORDBERG
Director

By: /s/ William W. Rucks, IV
WILLIAM W. RUCKS, IV
Director

Index To Financial Statements

Report of Independent Registered Public Accounting Firm 42

Consolidated Balance Sheets of PetroQuest Energy, Inc. as of
December 31, 2004 and 2003 43

Consolidated Statements of Income of PetroQuest Energy, Inc.
for the years ended December 31, 2004, 2003 and 2002 44

Consolidated Statements of Stockholders' Equity of PetroQuest Energy, Inc.
for the years ended December 31, 2004, 2003 and 2002 45

Consolidated Statements of Cash Flows of PetroQuest Energy, Inc.
for the years ended December 31, 2004, 2003 and 2002 46

Notes to Consolidated Financial Statements 47

Report Of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of
PetroQuest Energy, Inc.

We have audited the accompanying consolidated balance sheets of PetroQuest Energy, Inc. as of December 31, 2004 and 2003, and the related consolidated statements of income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2004. 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, 2004 and 2003, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2004 in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the Consolidated Financial Statements, effective January 1, 2003, the Company adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations.*

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of PetroQuest Energy, Inc.'s internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 2, 2005 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
New Orleans, Louisiana
March 2, 2005

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

	December 31, 2004	December 31, 2003
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,529	$ 779
Oil and gas revenue receivable	9,392	6,520
Joint interest billing receivable	3,655	2,575
Other current assets	1,017	1,005
Total current assets	15,593	10,879
Oil and gas properties:		
Oil and gas properties, full cost method	363,756	282,898
Unevaluated oil and gas properties	16,380	10,813
Accumulated depreciation, depletion and amortization	(168,453)	(133,482)
Oil and gas properties, net	211,683	160,229
Other assets, net of accumulated depreciation and amortization of $5,967 and $3,826, respectively	4,341	5,276
TOTAL ASSETS	$ 231,617	$ 176,384
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable to vendors	$ 24,176	$ 11,926
Advances from co-owners	2,265	2,752
Undistributed oil and gas proceeds	2,930	1,206
Hedging liability	4,536	1,780
Current portion of long-term debt	-	5,300
Accrued incentive compensation	2,500	591
Other accrued liabilities	3,615	2,623
Total current liabilities	40,022	26,178
Long-term debt	38,500	22,200
Long-term hedging liability	1,974	-
Asset retirement obligation	15,238	12,476
Deferred income taxes	14,606	7,803
Commitments and contingencies	-	-
Stockholders' equity:		
Common stock, $.001 par value; authorized 75,000 shares; issued and outstanding 44,685 and 44,542 shares, respectively	45	45
Paid-in capital	112,387	112,038
Unearned deferred compensation	-	(69)
Other comprehensive loss	(4,231)	(1,015)
Retained earnings (deficit)	13,076	(3,272)
Total stockholders' equity	121,277	107,727
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 231,617	$ 176,384

See accompanying Notes to Consolidated Financial Statements.

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

	Year Ended December 31, 2004	2003	2002
Revenues:			
Oil and gas sales	$ 84,595	$ 47,910	$ 48,141
Interest and other income	273	778	97
	84,868	48,688	48,238
Expenses:			
Lease operating expenses	13,161	9,449	9,988
Production taxes	1,549	884	614
Depreciation, depletion and amortization	35,435	27,098	28,196
General and administrative	6,212	4,444	5,009
Accretion of asset retirement obligation	833	682	-
Interest expense	2,817	579	278
Derivative expense	2	1,071	558
	60,009	44,207	44,643
Income from operations	24,859	4,481	3,595
Income tax expense	8,511	1,690	1,288
Income before cumulative effect of change in accounting principle	$ 16,348	$ 2,791	$ 2,307
Cumulative effect of change in accounting principle	-	849	-
Net income	$ 16,348	$ 3,640	$ 2,307
Earnings per common share:			
Basic			
Income before cumulative effect of change in accounting principle	$ 0.37	$ 0.06	$ 0.06
Cumulative effect of change in accounting principle	-	0.02	-
Net income	$ 0.37	$ 0.08	$ 0.06
Diluted			
Income before cumulative effect of change in accounting principle	$ 0.35	$ 0.06	$ 0.06
Cumulative effect of change in accounting principle	-	0.02	-
Net income	$ 0.35	$ 0.08	$ 0.06
Weighted average number of common shares:			
Basic	44,616	43,661	37,871
Diluted	46,438	44,181	39,997

See accompanying Notes to Consolidated Financial Statements.

PETROQUEST ENERGY, INC.
Consolidated Statements of Stockholders' Equity
(Amounts in Thousands)

	Common Stock	Paid-In Capital	Unearned Deferred Compensation	Other Comprehensive Loss	Retained Earnings (Deficit)	Total Stockholders' Equity
December 31, 2001	$ 33	$ 64,083	$ (682)	$ -	$ (9,219)	$ 54,215
Options and warrants exercised	-	178	-	-	-	178
Sale of common stock	10	42,040	-	-	-	42,050
Amortization of deferred compensation	-	-	345	-	-	345
Tax effect of deferred compensation	-	(128)	-	-	-	(128)
Derivative fair value adjustment, net of tax	-	-	-	(1,197)	-	(1,197)
Net income	-	-	-	-	2,307	2,307
December 31, 2002	$ 43	$ 106,173	$ (337)	$ (1,197)	$ (6,912)	$ 97,770
Options and warrants exercised	2	2,110	-	-	-	2,112
Sale of common stock	-	(6)	-	-	-	(6)
Amortization of deferred compensation	-	-	268	-	-	268
Tax effect of deferred compensation	-	16	-	-	-	16
Warrant fair value adjustment	-	3,745	-	-	-	3,745
Derivative fair value adjustment, net of tax	-	-	-	182	-	182
Net income	-	-	-	-	3,640	3,640
December 31, 2003	$ 45	$ 112,038	$ (69)	$ (1,015)	$ (3,272)	$ 107,727
Options and warrants exercised	-	170	-	-	-	170
Sale of common stock	-	203	-	-	-	203
Amortization of deferred compensation	-	-	69	-	-	69
Tax effect of deferred compensation	-	(24)	-	-	-	(24)
Derivative fair value adjustment, net of tax	-	-	-	(3,216)	-	(3,216)
Net income	-	-	-	-	16,348	16,348
December 31, 2004	$ 45	$ 112,387	$ -	$ (4,231)	$ 13,076	$ 121,277

See accompanying Notes to Consolidated Financial Statements.

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

	Year Ended December 31, 2004	2003	2002
Cash flows from operating activities:			
Net income	$ 16,348	$ 3,640	$ 2,307
Adjustments to reconcile net income to net cash provided by operating activities:			
Deferred tax expense	8,511	1,690	1,288
Amortization of debt issuance costs	1,678	531	261
Compensation expense	272	381	345
Depreciation, depletion and amortization	35,435	27,098	28,196
Derivative mark to market	(218)	(258)	416
Cumulative effect of change in accounting principle	-	(849)	-
Accretion of asset retirement obligation	833	682	-
Changes in working capital accounts:			
Accounts receivable	(2,871)	(20)	(918)
Joint interest billing receivable	(1,080)	(409)	2,443
Accounts payable and accrued liabilities	12,521	1,416	(3,862)
Other assets	(619)	(273)	(725)
Advances from co-owners	(487)	1,811	(1,376)
Plugging and abandonment escrow	-	-	1,034
Other	(13)	(1,250)	(231)
Net cash provided by operating activities	70,310	34,190	29,178
Cash flows from investing activities:			
Investment in oil and gas properties	(80,142)	(54,126)	(64,324)
Sale of oil and gas properties, net	-	-	17,321
Net cash used in investing activities	(80,142)	(54,126)	(47,003)
Cash flows from financing activities:			
Exercise of options and warrants	170	2,111	178
Proceeds from borrowing	39,000	39,600	23,000
Repayment of debt	(28,000)	(21,100)	(47,329)
Deferred financing costs	(588)	(1,027)	-
Issuance of common stock, net of expenses	-	(6)	42,050
Net cash provided by financing activities	10,582	19,578	17,899
Net increase (decrease) in cash and cash equivalents	750	(358)	74
Cash and cash equivalents at beginning of period	779	1,137	1,063
Cash and cash equivalents at end of period	$ 1,529	$ 779	$ 1,137
Supplemental disclosure of cash flow information			
Cash paid during the period from:			
Interest	$ 1,752	$ 435	$ 736
Income taxes	$ -	$ -	$ -

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 an exploration office in Houston, Texas. It is engaged in the exploration, development, acquisition and operation of oil and gas properties onshore and offshore in the Gulf Coast Basin, as well as in portions of Texas and Oklahoma.

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 and Pittrans, Inc. 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. Certain reclassifications of amounts previously reported have been made to conform to current year presentation.

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.

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, restoration, dismantlement and abandonment 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. Additionally, the capitalized costs of proved oil and gas properties cannot exceed the present value of the estimated net cash flow from its proved reserves (the full cost ceiling). The Company has adopted a SEC accepted method of calculating the full cost ceiling test whereby the liability recognized under SFAS 143 is netted against property cost and the future abandonment obligations are included in estimated future net cash flows. Transactions involving sales of reserves in place, unless significant, are recorded as adjustments to accumulated depreciation, depletion and amortization.

Upon the acquisition or discovery of oil and gas properties, management estimates the future net costs to be incurred to dismantle, abandon and restore the property using geological, engineering and regulatory data available. Such cost estimates are periodically updated for changes in conditions and requirements. Such estimated amounts are considered part of the full cost pool for purposes of amortization upon acquisition or discovery. Such costs are capitalized as oil and gas properties as the actual restoration, dismantlement and abandonment activities take place.

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 loan.

Cash and Cash Equivalents

The Company considers all highly liquid investments in overnight securities made through its commercial bank accounts, which result in available funds the next business day, to be cash and cash equivalents.

Income Taxes

The Company accounts for income taxes in accordance with Statement of Financial Accounting Standards (SFAS) No. 109. 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 where management deems appropriate. Other financial and income tax reporting differences occur as a result of statutory depletion.

Earnings per Common Share Amounts

Basic earnings per common share is computed by dividing net income by the weighted average number of shares of common stock outstanding during the year. 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 warrants considered common stock equivalents computed using the treasury stock method. A reconciliation between basic and diluted shares outstanding (in thousands) is as follows:

	Year Ended December 31,		
	2004	2003	2002
Basic shares outstanding	44,616	43,661	37,871
Effect of stock options	858	179	884
Effect of warrants	964	341	1,242
Diluted shares outstanding	46,438	44,181	39,997

Options to purchase 433,792 shares of common stock at $3.75 to $7.65 per share were outstanding during 2004 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 and warrants to purchase 3,385,334 shares of common stock at $2.29 to $7.65 per share were outstanding during 2003 but were not included in the computation of diluted earnings per share because the options' and warrants' exercise prices were greater than the average market price of the common shares. Options to purchase 273,667 shares of common stock at $5.56 to $7.65 per share were outstanding during 2002 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

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, 2004, 2003 and 2002 were not significant.

Certain Concentrations

Our production is sold on month to month contracts at prevailing prices. We attempt to diversify our sales and obtain credit protections such as letters of credit and parental guarantees from certain of our purchasers. The following table identifies customers from whom we derived 10% or more of our 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 financially disruptive effect on its business or financial condition.

	2004	2003	2002
Cokinos	(a)	12%	(a)
Equiva Trading Company	-	(a)	10%
Louis Dreyfus Corporation	26%	27%	(a)
Reliant Energy Services, Inc.	-	(a)	29%
Texon LP	24%	24%	28%

(a) Less than 10 percent

Fair Value of Financial Instruments

The fair value of cash and cash equivalents, accounts receivable and accounts payable approximate book value at December 31, 2004 and 2003 due to the short-term nature of these accounts. The fair value of the credit facilities approximate book value due to the variable rate of interest charged. Our hedging instruments are reflected at fair value based on quotes obtained from counterparties as discussed below.

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 equity through other comprehensive income, net of related taxes, to the extent the hedge is effective. The cash settlements of cash flow hedges are recorded into revenue. Instruments not qualifying for hedge accounting treatment are recorded in the balance sheet and changes in fair value are recognized in earnings as derivative expense (income). At December 31, 2004, our hedging contracts were considered effective cash flow hedges.

Oil and gas revenues include reductions related to the settlement of hedges totaling ($5,261,000), ($4,462,000) and ($861,000) during 2004, 2003 and 2002, respectively. The Company recognized $2,000, $1,071,000 and $558,000 in derivative expense during the years ended December 31, 2004, 2003 and 2002, respectively, as a result of the settlement of ineffective derivative contracts that expired in 2004. As of December 31, 2004, 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:			
2005	Swap	750 MMBtu	$4.55
First Quarter 2005	Costless Collar	11,000 MMBtu	$4.50 - 7.99
Second Quarter 2005	Costless Collar	8,000 MMBtu	$4.50 - 6.67
Third Quarter 2005	Costless Collar	5,500 MMBtu	$4.50 - 7.28
Fourth Quarter 2005	Costless Collar	4,500 MMBtu	$4.50 - 7.40
2006	Swap	1,500 MMBtu	$4.53
January - June 2006	Costless Collar	2,500 MMBtu	$4.50 - 9.27
Crude Oil:			
First Quarter 2005	Costless Collar	1,000 Bbls	$26.50 - 42.85
Second Quarter 2005	Costless Collar	750 Bbls	$25.33 - 35.03
July - December 2005	Costless Collar	500 Bbls	$23.00 - 26.20
2006	Costless Collar	200 Bbls	$23.00 - 26.40

At December 31, 2004, the Company recognized a liability of $6.5 million related to the estimated fair value of these derivative instruments.

New Accounting Standards

On December 16, 2004, the Financial Accounting Standards Board 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." Generally, the approach in SFAS 123(R) is similar to the approach in SFAS 123. However, SFAS 123(R) requires all share based payments to employees, including grants of employee stock options, to be recognized in the income statement based on their estimated fair values. Pro forma disclosure is no longer an alternative. SFAS 123(R) requires adoption in the first interim or annual period beginning after June 15, 2005. We expect to adopt the standard July 1, 2005.

SFAS 123(R) permits adoption using one of two methods. A "modified prospective" method in which compensation cost is recognized beginning with the effective date 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. An alternate method, the "modified retrospective" method includes the requirements of the modified prospective method described above, but also permits entities to restate based on the amounts previously recognized under SFAS 123 for purposes of pro forma disclosures either (a) all prior periods presented or (b) prior interim periods of the year of adoption.

The Company currently accounts for its stock-based compensation plans under the principles prescribed by APB Opinion No. 25. Accordingly, no stock option compensation cost is reflected in net income, as all options granted under the plan had an exercise price equal to the market value of the underlying common stock on the date of grant. Accordingly, the adoption of SFAS 123(R) will have a significant impact on our results of operations, but will have no impact on our overall financial position.

The specific impact of the adoption cannot be predicted at this time because it will depend on the level of share-based payments granted in the future. However, had we adopted SFAS 123(R) in prior periods, the impact would approximate the impact of SFAS 123 as described below. SFAS 123(R) also requires the benefits of tax deductions in excess of recognized compensation cost to be reflected as a financing cash flow, rather than as an operating cash flow as currently required. We did not recognize any excess tax deductions during 2004, 2003 or 2002 in connection with the exercise of stock options.

The following table illustrates the effect on net income and earnings per share if the Company had applied the fair value recognition provisions of SFAS No. 123, pursuant to the disclosure requirements of SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure" (in thousands, except per share data):

	Year Ended December 31,		
	2004	2003	2002
Net income	$ 16,348	$ 3,640	$ 2,307
Stock-based compensation:			
Add: expense included in reported results, net of tax	177	248	224
Deduct: fair value based method, net of tax	(1,191)	(541)	(904)
Pro forma net income	$ 15,334	$ 3,347	$ 1,627
Earnings per common share			
Basic - as reported	$ 0.37	$ 0.08	$ 0.06
Basic - pro forma	$ 0.34	$ 0.08	$ 0.04
Diluted - as reported	$ 0.35	$ 0.08	$ 0.06
Diluted - pro forma	$ 0.33	$ 0.08	$ 0.04

See Note 9 for additional disclosures of stock-based compensation under SFAS No. 148.

The Company adopted SFAS 143, "Accounting for Asset Retirement Obligations," effective January 1, 2003. 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 net difference between the Company's previously depleted abandonment costs and the amounts estimated under SFAS 143, after taxes, totaled a gain of $849,000, which was recognized during 2003 as a cumulative effect of a change in accounting principle. The gain was due to the effect on the historical depletion as a result of the retirement obligation being recorded at fair value. On a pro forma basis, the impact for the year ended December 31, 2002 would have increased net income by $360,000.

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

	Year Ended December 31, 2004
Asset retirement obligation at beginning of year	$ 12,476
Liabilities incurred	3,195
Liabilities settled	-
Accretion expense	833
Revisions in estimated cash flows	(111)
Asset retirement obligation at end of period	16,393
Less: current portion of obligation	(1,155)
Long-term asset retirement obligation	$ 15,238

In September 2004, the Securities and Exchange Commission adopted 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. We expect to begin applying SAB No. 106 in the first quarter of 2005.

In January 2003, the Financial Accounting Standards Board issued Interpretation No. 46, Consolidation of Variable Interest Entities (FIN 46), which requires companies to evaluate variable interest entities to determine whether to apply the consolidation provisions of FIN 46 to those entities. The consolidation provisions of FIN 46, if applicable, would apply to variable interest entities created after January 31, 2003 immediately, and to variable interest entities created before February 1, 2003 in the Company's interim period beginning October 1, 2003. The Company believes that it has no interests in these types of entities.

Note 2 – Equity

Other Comprehensive Income

The following table presents the Company's comprehensive income for years ended December 31, 2004 and 2003 (in thousands):

	Year Ended December 31, 2004	2003
Net income	$ 16,348	$ 3,640
Change in fair value of derivative instrument, accounted for as hedges, net of taxes	(3,216)	182
Comprehensive income	$ 13,132	$ 3,822

The Company accounts for derivatives in accordance with SFAS No. 133, as amended. When the conditions specified in SFAS 133 are met, the Company may designate these derivatives as hedges. At December 31, 2004 and 2003, the effect of derivative financial instruments is net of deferred income tax benefits of $1,732,000 and $546,000, respectively.

Unearned Deferred Compensation

In April 2001, the original owners of American Explorer L.L.C. entered into an agreement with an officer of the Company whereby they granted to the officer an option to acquire, at a fixed price, certain of the original shares the original owners were issued. As the fixed price of the April grant was below the market price as of the date of grant, the Company is recognizing non-cash compensation expense over the three-year vesting period of the option. In addition, the Original Owners granted to the officer an interest in a portion of the Common Stock issuable pursuant to the Contingent Stock Issue Rights ("CSIRs"), if any, that might be issued. This agreement is similar to agreements previously entered into with two other officers of the Company. Non-cash compensation expense is being recognized for the Common Stock issuable pursuant to the CSIRs granted to the three officers over the three-year vesting period based on the fair value of the Common Stock issuable pursuant to the CSIRs in May 2001, when the Common Stock issuable pursuant to the CSIRs was issued to the Original Owners. The Company has recorded the effects of the transactions as deferred compensation which became fully amortized during 2004. We recognized $69,000, $381,000 and $345,000, respectively, of non-cash compensation expense during the years ended December 31, 2004, 2003 and 2002.

Note 3 – Debt

The Company entered into a bank credit facility on May 14, 2003. Pursuant to the credit facility agreement, PetroQuest and our subsidiary PetroQuest Energy, L.L.C. (the "Borrower") have a $75 million revolving credit facility that permits the Borrower to borrow amounts from time to time based on the available borrowing base as determined in the bank credit facility. The bank credit facility is secured by a mortgage on substantially all of the Borrower's oil and gas properties, a pledge of the membership interest of the Borrower and PetroQuest's corporate guarantee of the indebtedness of the Borrower. The borrowing base under the bank credit facility is based upon the valuation as of April 1 and October 1 of each year of the Borrower's mortgaged properties, projected oil and gas prices, and any other factors deemed relevant by the lenders. The Company or the lenders may also request additional borrowing base re-determinations.

As of December 31, 2004, the borrowing base under the bank credit facility was $43 million and was subject to monthly reductions of $1.5 million beginning February 2005. The lenders will determine future monthly reductions in connection with each borrowing base re-determination. At December 31, 2004, we had $26.5 million of borrowings and no letters of credit issued pursuant to the bank credit facility.

Outstanding balances on the revolving credit facility bear interest at either the bank's prime rate plus a margin (based on a sliding scale of 0.75% to 1.25% based on borrowing base usage but never less than the Federal Funds Effective Rate plus 0.5%) or the Eurodollar rate plus a margin (based on a sliding scale of 2.0% to 2.5% depending on borrowing base usage). The bank credit facility also allows the Company to use up to $5 million of the borrowing base for letters of credit for fees equal to the applicable margin rate for Eurodollar advances.

The Company is subject to certain restrictive financial and non-financial covenants under the bank credit facility including a minimum current ratio of 1.0 to 1.0, as defined in the credit facility agreement. The bank credit facility also requires the Borrower to establish and maintain commodity hedges covering at least 50% of its proved developed producing reserves on a rolling twelve-month basis. As of December 31, 2004, the Company was in compliance with all of the covenants in the bank credit facility. The bank credit facility matures on May 14, 2006.

On November 6, 2003, we obtained a $20 million subordinated term credit facility from Macquarie Americas Corp. The sub-debt facility carries an interest rate of prime plus 5.5%, is secured by a second mortgage on substantially all of our oil and gas properties and matures November 30, 2006. The sub-debt facility is available for advances at any time until December 31, 2005, subject to the restrictive covenants of the sub-debt facility and Macquarie approval. At closing, Macquarie received warrants to purchase 1,250,000 shares of our common stock at an exercise price of $2.30 per share.

In conjunction with the December 2003 property acquisition, the sub-debt facility was amended, the original warrants were cancelled and 2,250,000 warrants were issued to Macquarie. During January 2004, the sub-debt facility, including the note, liens, warrants and all other rights of Macquarie thereunder, was assigned to Macquarie Bank Limited, an affiliate of Macquarie Americas Corp. During February 2005, Macquarie exercised the outstanding warrants utilizing a cashless exercise provision resulting in the issuance of 1,506,466 shares.

As of December 31, 2004, the Company had $12 million borrowed under the sub-debt facility, which was primarily used to fund the acquisition of properties in the Southeast Carthage field. The sub-debt facility contains certain restrictive financial and non-financial covenants, including a minimum current ratio of 1.0 to 1.0, a total debt threshold of $60 million and a cumulative minimum production and net operating cash flow threshold, all as defined in the sub-debt facility. The sub-debt facility also requires the Company to establish and maintain commodity hedges covering at least 65% of its proved developed producing reserves through November 2006. As of December 31, 2004, the Company was in compliance with all of the covenants in the sub-debt facility.

Note 4 – Related Party Transactions

Three of our officers, Charles T. Goodson, Ralph J. Daigle and Stephen H. Green, or their affiliates, are working interest owners and overriding interest owners and E. Wayne Nordberg, one of our directors, is a working interest owner in certain properties operated by us or in which we also hold 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 the year ended December 31, 2004, in their capacities as working interest owners or overriding royalty interest owners, revenues, net of costs were disbursed to Messrs. Goodson, Daigle and Green, or their affiliates, in the amounts of $380,644, $259,310 and $480,446, respectively, and with respect to the working interests of Mr. Nordberg, revenues exceeded costs by $75,509. Net amounts received by Messrs. Goodson, Daigle and Green, or their affiliates, totaled $841,350, $481,276 and $107,367, respectively, during the year ended December 31, 2003 and $483,958, $284,541 and $44,569, respectively, during 2002. During the years ended December 31, 2003 and 2002, costs exceeded revenues with respect to Mr. Nordberg's working interests by $89,225 and $96,698, respectively. With respect to Messrs. Goodson and Daigle, or their affiliates, gross revenues attributable to interests, properties or participation rights held by them prior to Messrs. Goodson and Daigle joining us as officers and directors on September 1, 1998 represent approximately 79% and 69%, respectively, of the gross revenues received by them in 2004.

In our capacity as operator, we incur drilling and operating costs that are billed to our partners based on their respective working interests. At December 31, 2004, our joint interest billing receivable included $38,000 from related parties attributable to their share of costs. This represents approximately 1% of our total joint interest billing receivable at December 31, 2004.

Note 5 – Common Stock

During 2002, the Company completed the offering of 10,193,600 shares of its common stock. After underwriting discounts, the Company realized proceeds of approximately $42.3 million.

Note 6 – Investment in Oil and Gas Properties

The following tables disclose certain financial data relative to the Company's evaluated 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, 2004	2003	2002
Acquisition costs:			
Proved	$ 23,041	$ 22,679	$ 1,023
Unproved	5,963	1,769	6,052
Exploration costs:			
Proved	28,298	5,170	16,183
Development costs	24,204	21,685	37,247
Cumulative effect of change in accounting principle costs	-	8,150	-
Capitalized general and administrative and interest costs	4,919	4,062	4,283
Total costs incurred	$ 86,425	$ 63,515	$ 64,788

	For the Year Ended December 31, 2004	2003	2002
Accumulated depreciation, depletion and amortization (DD&A)			
Balance, beginning of year	$ (133,482)	$ (109,450)	$ (64,379)
Provision for DD&A	(34,971)	(26,654)	(27,751)
Effect of change in accounting principle	-	2,622	-
Sale of proved properties	-	-	(17,320)
Balance, end of year	$ (168,453)	$ (133,482)	$ (109,450)
DD&A per Mcfe	$ 2.46	$ 2.76	$ 2.08

Non-cash additions to oil and gas properties related to SFAS 143 totaled $3.1 million in 2004 and $10.5 million during 2003.

At December 31, 2004 and 2003, unevaluated oil and gas properties totaled $16,380,000 and $10,813,000, respectively, and were not subject to depletion. All of the unevaluated costs at December 31, 2004 and 2003 related to acquisition costs and related capitalized interest. We capitalized $883,000 and $451,000 of interest during 2004 and 2003, respectively. Of the total unevaluated oil and gas property costs at December 31, 2004, $6,846,000 was incurred in 2004, $2,347,000 was incurred in 2003 and $7,187,000 was incurred in prior years. Management expects that the majority of the unevaluated costs at December 31, 2004 will be evaluated within the next three years.

Note 7 – Income Taxes

The Company follows the provisions of SFAS No. 109, "Accounting for Income Taxes," which provides for recognition of a deferred tax asset for deductible temporary timing differences, operating loss carryforwards, statutory depletion carryforwards and tax credit carryforwards net of a "valuation allowance."

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

	December 31, 2004		December 31, 2003	
Net operating loss carryforwards	$	12,565	$	7,659
Percentage depletion carryforward		1,839		1,341
Alternative minimum tax credit		115		4
Deferred Compensation		-		(355)
Temporary differences:				
Oil and gas properties - full cost		(29,278)		(17,151)
Derivative mark to market		-		546
Compensation expense		153		153
	$	(14,606)	$	(7,803)

For tax reporting purposes, the Company had operating loss carryforwards of $33,776,000 and $20,590,000 at December 31, 2004 and 2003, respectively. If not utilized, such carryforwards would begin expiring in 2006 and would completely expire by the year 2023. The Company had available for tax reporting purposes $5,257,000 in statutory depletion deductions that may be carried forward indefinitely.

Income tax expense for each of the years ended December 31, 2004, 2003 and 2002 (amounts in thousands) was different than the amount computed using the Federal statutory rate (35%) for the following reasons:

	For the Year Ended December 31, 2004		2003		2002	
Amount computed using the statutory rate	$	8,701	$	1,568	$	1,258
Increase (reduction) in taxes resulting from:						
State & local taxes		547		99		79
Percentage depletion carryforward		(498)		(50)		(129)
Alternative minimum credit carryforward		(111)		-		-
Other		(128)		73		80
Income tax expense	$	8,511	$	1,690	$	1,288

Note 8 – 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, which expire on various dates through 2010.

Future minimum lease commitments as of December 31, 2004 under these operating leases are as follows (in thousands):

2005	$	832
2006		772
2007		742
2008		741
2009		755
Thereafter		647
	$	4,489

Beginning in July 2003, we subleased office space to third parties. For the years ended December 31, 2004 and 2003, we received $74,000 and $27,000, respectively, relative to subleased office space. Total rent expense under operating leases, net of amounts received under sublease arrangements, was approximately $654,000, $639,000 and $577,000 in 2004, 2003 and 2002, respectively. A minimum lease rental to be received from the sublease of office space is $73,000 and $31,000 during 2005 and 2006, respectively.

Note 9 – Employee Benefit Plans

The Company currently has one stock option plan. Stock options generally become exercisable 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.

A summary of the Company's stock options as of December 31, 2004, 2003 and 2002 and changes during the years ended on those dates is presented below:

	Year Ended December 31, 2004		2003		2002	
	Number of Options	Wgtd. Avg. Price	Number of Options	Wgtd. Avg. Price	Number of Options	Wgtd. Avg. Price
Outstanding at beginning of year	2,069,634	$ 3.03	2,197,353	$ 3.14	2,238,766	$ 2.94
Granted	1,239,500	3.32	150,000	1.94	112,000	6.17
Expired/cancelled/forfeited	(556,167)	5.41	(235,253)	3.76	(66,910)	3.75
Exercised	(88,333)	1.93	(42,466)	1.23	(86,503)	1.44
Outstanding at end of year	2,664,634	2.70	2,069,634	3.03	2,197,353	3.14
Options exercisable at year-end	1,892,963	2.46	1,690,371	2.77	1,453,166	2.36
Options available for future grant	621,066		1,359,069		770,208	
Weighted average fair value of options granted during the year	$ 1.93		$ 1.18		$ 3.93	

The fair value of each option granted during the periods presented is estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions: (a) dividend yield of 0%, (b) expected volatility ranges of 64.30%-67.40%, 69.90%-73.90% and 74.50%-74.90% in 2004, 2003 and 2002, respectively, (c) risk-free interest rate ranges of 3.21%-3.98%, 2.93% - 3.39% and 4.17% - 4.54% in 2004, 2003 and 2002, respectively, and (d) expected life of 5 years for all grants.

The following table summarizes information regarding stock options outstanding at December 31, 2004:

Range of Exercise Price	Options Outstanding 12/31/04	Wgtd. Avg. Remaining Contractual Life	Wgtd. Avg. Exercise Price	Options Exercisable 12/31/04	Wgtd. Avg. Exercise Price
$0.85 - $0.94	379,300	4.0 years	$0.90	379,300	$0.90
$1.44 - $2.29	515,000	6.7 years	$1.75	414,995	$1.71
$3.13 - $3.38	1,568,667	7.7 years	$3.20	1,053,667	$3.15
$3.53 - $7.65	201,667	9.3 years	$4.60	45,001	$6.66
	2,664,634	7.1 years	$2.70	1,892,963	$2.46

Note 10 – Oil and Gas Reserve Information – Unaudited

The Company's net proved oil and gas reserves at December 31, 2004 have been estimated by independent petroleum consultants 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.

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

The following table sets forth an analysis of the Company's estimated quantities of net proved and proved developed oil (including condensate) 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, 2001	6,213	44,944
Revisions of previous estimates	(1,204)	(8,955)
Extensions, discoveries and other additions	1,438	19,453
Sale of producing properties	(260)	(10,540)
Production	(929)	(7,765)
Proved reserves as of December 31, 2002	5,258	37,137
Revisions of previous estimates	(369)	(7,935)
Extensions, discoveries and other additions	83	6,830
Purchase of producing properties	217	28,410
Sale of producing properties	(200)	(1,456)
Production	(744)	(5,193)
Proved reserves as of December 31, 2003	4,245	57,793
Revisions of previous estimates	(396)	3,461
Extensions, discoveries and other additions	559	14,575
Purchase of producing properties	124	12,545
Production	(818)	(9,305)
Proved reserves as of December 31, 2004	3,714	79,069
Proved developed reserves:		
As of December 31, 2002	4,201	17,409
As of December 31, 2003	3,446	34,655
As of December 31, 2004	2,984	50,809

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, 2004	2003	2002
Future cash flows	$ 622,941	$ 460,073	$ 337,776
Future production costs	(111,165)	(100,213)	(57,572)
Future development costs	(68,289)	(66,511)	(63,270)
Future income taxes	(94,454)	(53,514)	(36,687)
Future net cash flows	349,033	239,835	180,247
10% annual discount	(91,279)	(64,609)	(40,831)
Standardized measure of discounted future net cash flows	$ 257,754	$ 175,226	$ 139,416

Changes in Standardized Measure

	Year Ended December 31, 2004	2003	2002
Standardized measure at beginning of year	$ 175,226	$ 139,416	$ 75,047
Sales and transfers of oil and gas produced, net of production costs	(69,885)	(37,577)	(38,400)
Changes in price, net of future production costs	46,382	23,007	78,648
Extensions and discoveries, net of future production and development costs	73,535	38,883	83,005
Changes in estimated future development costs, net of development costs incurred during this period	10,122	10,577	19,059
Revisions of quantity estimates	4,076	(35,796)	(56,166)
Accretion of discount	21,435	16,605	8,823
Net change in income taxes	(29,375)	(12,507)	(13,448)
Purchase of reserves in place	27,623	40,605	-
Sale of reserves in place	-	(3,802)	(12,899)
Changes in production rates (timing) and other	(1,386)	(4,185)	(4,253)
Standardized measure at end of year	$ 257,754	$ 175,226	$ 139,416

The weighted average prices of oil and gas used with the above tables at December 31, 2004, 2003 and 2002 were $43.85, $32.24 and $30.44 per barrel, respectively, and $5.82, $5.59 and $4.79 per Mcfe, respectively. The Company's cash flow amounts include a reduction for estimated plugging and abandonment costs that has also been reflected as a liability on the balance sheet at December 31, 2004 and 2003, in accordance with SFAS No. 143.

Note 11 – Summarized Quarterly Financial Information – Unaudited

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

2004:	Quarter Ended March-31	June-30	September-30	December-31
Revenues	$ 18,202	$ 21,497	$ 22,572	$ 22,597
Expenses	15,030	17,260	18,632	17,598
Net income	$ 3,172	$ 4,237	$ 3,940	$ 4,999
Earnings per share:				
Basic	$ 0.07	$ 0.10	$ 0.09	$ 0.11
Diluted	$ 0.07	$ 0.09	$ 0.08	$ 0.11
2003:				
Revenues	$ 16,164	$ 9,101	$ 9,857	$ 13,566
Expenses	14,020	10,799	9,628	11,450
Income before cumulative effect of change in accounting principle	$ 2,144	$ (1,698)	$ 229	$ 2,116
Net income (loss)	$ 2,993	$ (1,698)	$ 229	$ 2,116
Earnings (loss) per common share:				
Basic				
Income (loss) before cumulative effect of change in accounting principle	$ 0.05	$ (0.04)	$ 0.01	$ 0.05
Net income (loss)	$ 0.07	$ (0.04)	$ 0.01	$ 0.05
Diluted				
Income (loss) before cumulative effect of change in accounting principle	$ 0.05	$ (0.04)	$ 0.01	$ 0.05
Net income (loss)	$ 0.07	$ (0.04)	$ 0.01	$ 0.05

(1) The above quarterly earnings (loss) per share may not total to the full year per share amount, as the weighted average number of shares outstanding for each quarter fluctuated as a result of the assumed exercise of stock options.

Exhibit 23.1

Consent Of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the Registration Statements (Form S-8 File Nos. 333-67578, 333-63920, 333-52700, 333-42520, 333-65401, 333-102758, 333-88846, and 333-89961) of PetroQuest Energy, Inc., of our reports dated March 2, 2005, with respect to the consolidated financial statements of PetroQuest Energy, Inc., PetroQuest Energy, Inc. management's assessment of the effectiveness of internal control over financial reporting, 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, 2004.

/s/ Ernst & Young LLP
New Orleans, Louisiana
March 4, 2005

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, 2004, and to the incorporation by reference thereof into the Company's previously filed Registration Statements on Form S-3 and Form S-8, 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, 2002, 2003 and 2004. 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
March 3, 2005

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
March 3, 2005

Exhibit 31.2

I, Michael O. Aldridge, 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/ Michael O. Aldridge
Michael O. Aldridge
Chief Financial Officer
March 3, 2005

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 period ending December 31, 2004 (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
March 3, 2005

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 period ending December 31, 2004 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, Michael O. Aldridge, 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/ Michael O. Aldridge
Michael O. Aldridge
Chief Financial Officer
March 3, 2005

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.

Ralph J. Daigle †
Vice Chairman
PetroQuest Energy, Inc.

Michael O. Aldridge
Senior Vice President and Chief Financial Officer
PetroQuest Energy, Inc.

W.J. Gordon III *# ^
Vice President of Strategic Planning
Franciscan Missionaries of Our Lady Health System

Michael L. Finch *# ^
Private Investments

E. Wayne Nordberg *# ^
Ingalls & Snyder, LLC

William W. Rucks, IV *# ^
Private Investments

* Member of the Compensation Committee
\# Member of the Audit Committee
^ Member of the Nominating & Corporate Governance Committee
† Mr. Daigle will resign as Vice Chairman effective March 31, 2005

Senior Management

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

Ralph J. Daigle
Vice Chairman

Michael O. Aldridge
Senior Vice President and Chief Financial Officer

Art M. Mixon
Senior Vice President – Operations

Daniel G. Fournerat
Senior Vice President, General Counsel and Secretary

Dalton F. Smith III
Senior Vice President – Business Development and Land

Stephen H. Green
Senior Vice President – Exploration

James S. Blair
Vice President – Business Development

Corporate Address

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

Exploration Office

PetroQuest Energy, Inc.
450 Gears Road, Suite 330
Houston, Texas 77067
Tel: (713) 784-8300
Fax: (713) 784-8327

Transfer Agent and Registrar

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

Independent Auditors

Ernst & Young LLP
New Orleans, Louisiana 70170

Legal Counsel

Onebane, Bernard, Torian, Diaz,
McNamara & Abell
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. on May 12, 2005 at the City Club at River Ranch at 221 Elysian Fields Drive, Lafayette, Louisiana 70508

Form 10-K

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

Common Stock Listing

PQUE
NASDAQ
LISTED

PetroQuest Energy, Inc.

etroQuest Energy, Inc.
00 East Kaliste Saloom Road, Suite 6000
afayette, Louisiana 70508
el: (337) 232-7028 Fax: (337) 232-0044
Web: www.petroquest.com